



CRESCENT POINT ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

For the Year Ended December 31, 2007

Dated March 31, 2008

TABLE OF CONTENTS

NOTE REGARDING FORWARD-LOOKING STATEMENTS	1
GLOSSARY	2
SELECTED ABBREVIATIONS	4
CURRENCY OF INFORMATION	5
OUR ORGANIZATIONAL STRUCTURE	5
The Trust	5
CPRI	5
CPC Trust	5
Limited Partnership	5
CPGPC	5
Intercorporate Relationships	5
Organizational Structure of the Trust	6
GENERAL DEVELOPMENT OF THE BUSINESS OF THE TRUST	7
History	7
DESCRIPTION OF OUR BUSINESS	10
Strategy	10
Risk Management and Marketing	10
Revenue Sources	11
Competition	12
Seasonal Factors	12
Personnel	12
Reorganizations	12
Social and Environmental Policies	13
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	13
THE TRUST	13
Disclosure of Reserves Data	13
Reserves Data – Forecast Prices and Costs	14
Notes and Definitions	15
Pricing Assumptions – Forecast Prices and Costs	19
Reconciliations of Changes in Reserves and Future Net Revenue	20
Undeveloped Reserves	20
Proved Undeveloped Reserves	20
Probable Undeveloped Reserves	20
Significant Factors or Uncertainties Affecting Reserves Data	21
Future Development Costs	21
Major Oil and Gas Properties	21
Oil and Gas Wells	23
Properties With No Attributed Reserves	23
Drilling Activity	24
Additional Information Concerning Abandonment and Reclamation Costs	24
Tax Horizon	24
Costs Incurred	24
Production Estimates	24
Production History	25
Production Volume by Field	26
ADDITIONAL INFORMATION RESPECTING THE TRUST	26
Trust Units	26
Income Stream	27
The Participating Note	27
Unitholder Limited Liability	27
Issuance Of Trust Units	27

Cash Distributions	27
Redemption Right.....	27
Non-Resident Unitholders	28
Meetings of Trust Unitholders.....	29
Exercise of Voting Rights.....	29
Trustee.....	30
Delegation of Authority, Administration and Trust Governance.....	30
Liability of the Trustee.....	30
Amendments to the Trust Indenture.....	30
Takeover Bid	31
Termination of the Trust.....	31
Reporting to Trust Unitholders	32
Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan.....	32
Credit Facilities.....	32
ADDITIONAL INFORMATION RESPECTING CPRI.....	32
Directors and Officers	32
Share Capital.....	37
Common Shares.....	37
First Preferred Shares.....	37
Administration Agreement.....	37
INDUSTRY CONDITIONS	37
Pricing and Marketing – Natural Gas	38
Pricing and Marketing – Oil.....	38
The North American Free Trade Agreement.....	38
Royalties and Incentives.....	38
Environmental Protection Requirements.....	38
Environmental Regulation.....	39
RISK FACTORS.....	39
Reserve Estimates.....	39
Volatility of Oil and Natural Gas Prices.....	40
Operating Costs and Production Levels.....	40
Reinvestment of Cash Flow to Fund Ongoing Operations.....	41
Marketing of Oil and Natural Gas Production.....	41
Fluctuations in Foreign Currency Exchange Rates	41
Acquisition of Additional Reserves.....	41
Scope of Operations.....	41
Reliance on Reserve Estimates.....	42
Operational Matters.....	42
Delays in Business Operations.....	42
Debt Service	42
Liquidity	43
Competition.....	43
Operational Hazards and the Availability of Insurance.....	43
Environmental Concerns.....	43
Unforeseen Title Defects.....	44
Aboriginal Land Claims	44
Changes in Tax and Other Laws	44
Loss of Mutual Fund Trust Status.....	44
Income Tax Matters	45
Nature of Trust Units and the Trust.....	47
Market Factors	47
Loss of Key Personnel.....	47
Dilution.....	47
Availability of an Active Market for the Trust Units	47
Unitholder Limited Liability.....	47
Availability of Redemption Rights for Trust Units	48

DISTRIBUTIONS	48
MARKET FOR SECURITIES	50
CONFLICTS OF INTEREST	52
LEGAL PROCEEDINGS.....	52
AUDIT COMMITTEE	52
General.....	52
Mandate of the Audit Committee.....	52
Relevant Education and Experience of Audit Committee Members	53
External Auditor Services Fees	54
Audit Committee Oversight.....	54
TRANSFER AGENT AND REGISTRARS	54
MATERIAL CONTRACTS	54
INTERESTS OF EXPERTS	54
ADDITIONAL INFORMATION	55
APPENDIX A - AUDIT COMMITTEE TERMS OF REFERENCE	
APPENDIX B - RESERVES COMMITTEE TERMS OF REFERENCE	
APPENDIX C - REPORTS ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS OR AUDITORS	
APPENDIX D - REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION	

NOTE REGARDING FORWARD-LOOKING STATEMENTS

This annual information form, the documents incorporated by reference herein, and other reports and filings made with the securities regulatory authorities include forward-looking statements. All forward-looking statements are based on our beliefs and assumptions based on information available at the time the assumption was made. The use of any of the words “anticipate”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “should”, “believe” and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Trust and Crescent Point Resources Inc. (“CPRP”), believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

In particular, this annual information form contains forward-looking statements pertaining, among other things, to the following:

- anticipated financial performance;
- business prospects;
- oil and natural gas production levels;
- capital expenditure programs;
- the quantity of the oil and natural gas reserves;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes.

By its nature, such forward-looking information is subject to various risks, uncertainties and other factors, including those material risks discussed in the AIF under “*Risk Factors*” and in the MD&A under “*Business Risks and Prospects*”, which could cause our actual results and experience to differ materially from the anticipated results or other expectations expressed. The material assumptions in making these forward-looking statements are disclosed in the MD&A under the headings “*Non-GAAP Financial Measures*”, “*Taxes*”, “*Cash Distributions*”, “*Taxation of Cash Distributions*”, “*Capital Expenditures*”, “*Asset Retirement Obligation*”, “*Liquidity and Capital Resources*”, “*Critical Accounting Estimates*”, “*New Accounting Pronouncements*”, “*Business Risk and Prospects*” and “*Outlook*”.

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond the Crescent Point’s control, including the impact of general economic conditions; industry conditions including changes to laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition and the lack of availability of qualified personnel or management; fluctuations in commodity prices; foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. In addition, there are numerous risks and uncertainties associated with oil and gas operations and the evaluation of oil and gas reserves. Therefore, Crescent Point’s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits Crescent Point will derive there from.

Readers are cautioned not to place undue reliance on the forward-looking information, which is given as of the date it is expressed in this AIF or otherwise. We do not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required pursuant to applicable securities laws.

GLOSSARY

In this annual information form, the capitalized terms set forth below have the following meanings:

“**1230698**” means 1230698 Alberta Ltd., a corporation continued under the *Business Corporations Act* (Alberta), a predecessor corporation to CPGPC.

“**1275920**” means 1275920 Alberta Ltd., a corporation formed under the laws of the province of Alberta and a wholly owned subsidiary of the Trust, a predecessor to CPGPC.

“**Administration Agreement**” means the amended and restated administration agreement with the Trust dated March 1, 2007 delegating broad authority to CPRI to effect the actual administration duties of the Trustee;

“**Arrangement**” means the plan of arrangement involving the Trust, Crescent Point Energy Ltd., Tappit Resources Ltd., StarPoint Energy Ltd. and Crescent Point Acquisition Ltd. made effective September 5, 2003, as more particularly described under the heading “*Our Organizational Structure – The Trust*”.

“**Bulldog**” means Bulldog Energy Inc.

“**Bulldog Arrangement**” means the plan of arrangement involving Bulldog, Bulldog Resources Inc., Flatland Exploration Ltd., Helmsman Resources Ltd., the Trust, CPRL and 1200881 Alberta Ltd. completed on November 29, 2005, as more particularly described under the heading “*General Development of the Business of the Trust - History*”.

“**Canex**” means Canex Energy Inc.

“**Canex Arrangement**” means the plan of arrangement effected on May 30, 2006 under section 193 of the ABCA pursuant to which the Trust indirectly acquired Canex.

“**Cantuar/Battrum Acquisition**” has the meaning ascribed thereto under “*General Development of the Business of the Trust – History – 2006*”.

“**CPC Trust**” means Crescent Point Commercial Trust, a wholly-owned subsidiary of the Trust settled under the laws of the Province of Alberta.

“**CPGPC**” means Crescent Point General Partner Corp., a corporation amalgamated under the *Business Corporation Act* (Alberta).

“**CPEL**” means Crescent Point Exchange Limited, a corporation amalgamated under the *Business Corporations Act* (Alberta).

“**CPC Trust Indenture**” means the trust indenture governing CPC Trust, as amended from time to time;

“**CPRI**” means Crescent Point Resources Inc., a corporation incorporated under the *Business Corporations Act* (Alberta).

“**CPRL**” means Crescent Point Resources Ltd., a predecessor corporation to CPGPC.

“**Crescent Point**” or the “**Trust**” means Crescent Point Energy Trust, an unincorporated open ended investment trust governed by the laws of the Province of Alberta.

“**Crescent Point Energy Partnership**” means a general partnership, formed under the laws of the Province of Alberta, having CPRL, 1079440 Alberta Ltd., a predecessor corporation to CPRL as partners.

“**Exchangeable Shares**” means the Series A Exchangeable Shares of CPRL.

“**Greenhouse Gases**” or “**GHGs**” means any or all of carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and a sulphur hexafluoride (SF₆).

“**GLJ**” means GLJ Petroleum Consultants.

“**Innova**” means Innova Exploration Ltd.

“**Landex**” means Landex Petroleum Corp.

“**Landex Arrangement**” means the plan of arrangement involving the Trust and Landex completed on March 26, 2008, as more particularly described under the heading “*General Development of the Business of the Trust – History - 2008*”.

“**Limited Partnership**” means Crescent Point Resources Limited Partnership, a limited partnership formed under the laws of the Province of Alberta, having CPGPC as the general partner and the Trust and CPC Trust as limited partners.

“**LP Agreement**” means the limited partnership agreement among CPGPC, CPC Trust and the Trust in respect of the Limited Partnership.

“**LP Assets**” means all of the material oil and gas assets held in the Limited Partnership.

“**Mission**” means Mission Oil & Gas Inc., a corporation incorporated under the *Business Corporations Act* (Alberta).

“**Mission Arrangement**” means the plan of arrangement involving Mission, the Trust, 1275920 and CPGPC completed on February 9, 2007, as more particularly described under the heading “*General Development of the Business of the Trust – History*”.

“**Mission LP Agreement**” means the agreement between Mission and Mission Exploration Inc. governing the Mission Oil & Gas Limited Partnership.

“**NI 51-101**” means “*National Instrument 51-101 – Standards for Disclosure for Oil and Gas Activities*”.

“**Participating Note**” means the participating note issued by CPC Trust to the Trust on January 6, 2004, as more fully described under “*Additional Information Respecting the Trust – CPC Trust Notes*”.

“**Pilot**” means Pilot Energy Ltd.

“**Pilot Arrangement**” means the plan of arrangement involving Pilot, the Trust and CPGPC dated effective January 16, 2008, as more particularly described under the heading “*General Development of the Business of the Trust – History - 2008*”.

“**Redemption Notes**” means the promissory notes issuable by the Trust under the Trust Indenture having terms and conditions substantially similar to those of the Note.

“**Restricted Unit Bonus Plan**” means an incentive bonus compensation plan for eligible participants including directors, officers, employees and consultants of the Trust and its affiliates.

“**Shelter Bay**” means Shelter Bay Energy Inc.

“**Sproule**” means Sproule Associates Limited.

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

“**Trust Indenture**” has the meaning ascribed thereto under “*Our Organizational Structure – The Trust*”.

“**Trust Units**” means the trust units of the Trust.

“**Trustee**” means Olympia Trust Company, the initial trustee of the Trust, or such other trustee, from time to time, of the Trust.

“**TSX**” means the Toronto Stock Exchange.

“**Unitholders**” means holders of Trust Units.

“**Voting and Exchange Trust Agreement**” means the voting and exchange trust agreement dated as of the effective date of the Arrangement among the Trust, CPRL, Crescent Point Exchange Ltd. and Olympia Trust Company.

In this annual information form, references to “dollars” and “\$” are to the currency of Canada, unless otherwise indicated.

SELECTED ABBREVIATIONS

In this annual information form, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
bbl	Barrel	Mcf	thousand cubic feet
bbls	Barrels	Mcfe	thousand cubic feet of gas equivalent converting one barrel of oil to 6 Mcf of natural gas equivalent
Mbbls	thousand barrels	MMcf	million cubic feet
MMbbls	million barrels	Mcf/d	thousand cubic feet per day
Mstb	thousand stock tank barrels	MMcf/d	million cubic feet per day
bbl/d	barrels per day	MMBTU	million British Thermal Units
NGLs	natural gas liquids	Bcf	billion cubic feet
STB	stock tank barrels	GJ	Gigajoule

Other

API	American Petroleum Institute
° API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
boe	barrel of oil equivalent of natural gas and crude oil on the basis of 1 boe for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
boe/d	barrel of oil equivalent per day
m ³	cubic metres
Mboe	thousand barrels of oil equivalent
MMboe	Million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CURRENCY OF INFORMATION

The information set out in this renewal annual information form is stated as at December 31, 2007 unless otherwise indicated. Capitalized terms used but not defined in the text are defined in the Glossary.

OUR ORGANIZATIONAL STRUCTURE

The Trust

Crescent Point Energy Trust (the “Trust” and, together with its direct and indirect subsidiaries and partnerships, where appropriate, “we”, “our” or “us”) is an open ended unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture dated as of July 22, 2003, amended and restated on August 27, 2003 and January 6, 2004, and amended pursuant to the Supplemental Trust Indenture dated December 15, 2005, amended and restated by a supplemental trust indenture dated February 28, 2007, and amended and restated on March 1, 2007, between CPRI and Olympia Trust Company (the “Trust Indenture”). Pursuant to the Trust Indenture and the Administration Agreement, CPRI has been delegated certain matters in respect of the management and administration of the Trust. Our head and principal office is located at 2800, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 3Y6 and our registered office is 3300, 421 - 7th Avenue S.W., Calgary, Alberta T2P 4K9.

The principal undertakings of the Trust are to issue Trust Units and to acquire and hold debt and other interests. Our direct and indirect wholly-owned subsidiaries carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto. The primary assets of the Trust are currently the shares in CPRI and CPEL, units and debt in CPC Trust and units in the Limited Partnership. In addition, we continually review and assess numerous corporate and asset acquisition opportunities as part of our ongoing acquisition program.

We make monthly cash distributions to Unitholders from our net cash flow. Our primary sources of cash flow are distributions from the Limited Partnership and the CPC Trust and interest payments from CPC Trust.

Olympia Trust Company has been appointed as trustee under the Trust Indenture. The beneficiaries of the Trust are holders of the outstanding Trust Units. The principal and head office of Olympia Trust Company is located at 2300, 125 – 9th Avenue S.E., Calgary, Alberta, T2G 0P6.

CPRI

CPRI administers the affairs of the Trust pursuant to the Administration Agreement. The Trust holds 100% of the issued and outstanding common shares of CPRI. CPGPC is a wholly-owned subsidiary of CPRI.

CPC Trust

CPC Trust is a commercial trust governed by the laws of the Province of Alberta. The Trust holds 100% of the issued and outstanding trust units of CPC Trust. In turn, CPC Trust holds an interest in the Limited Partnership.

Limited Partnership

The Limited Partnership is a limited partnership governed by the laws of the Province of Alberta. The limited partners of the Limited Partnership are CPC Trust and the Trust. The general partner of the Limited Partnership is CPGPC. The Limited Partnership owns the LP Assets, from which we generate cash flow.

CPGPC

CPGPC, is a wholly-owned subsidiary of CPRI. CPGPC acts as a general partner of the Limited Partnership.

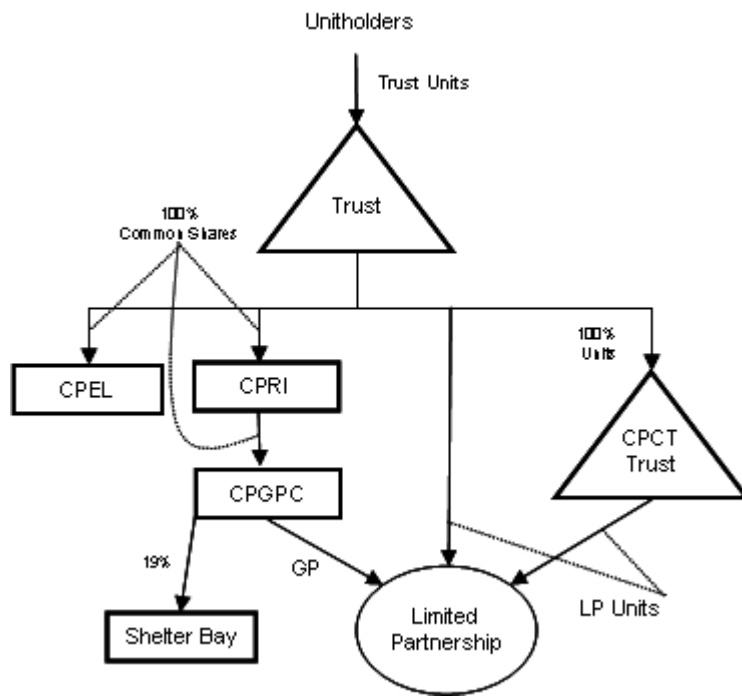
Intercorporate Relationships

The following table provides the name, the percentage of voting securities owned by the Trust and the jurisdiction of incorporation, continuance or formation of the Trust’s material subsidiaries as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Jurisdiction of Incorporation/ Formation
CPRI	100%	Alberta
CPGPC	100%	Alberta
CPC Trust	100%	Alberta
CPEL	100%	Alberta
Limited Partnership	100%	Alberta
Shelter Bay	19%	Alberta

Organizational Structure of the Trust

The following diagram describes the intercorporate relationships among the Trust and its material direct and indirect subsidiaries described above as at March 31, 2008. Reference should be made to the appropriate sections of this Annual Information Form for a complete description of the structure of the Trust.



Notes:

- (1) The Unitholders own 100% of the equity of the Trust.
- (2) Cash distributions are made on a monthly basis to Unitholders based upon the Trust's cash flow. The Trust's primary sources of cash flow are distributions from the Limited Partnership and CPC Trust and interest payments from CPC Trust.
- (3) The Trust has filed an undertaking with the applicable securities authorities in accordance with Part 3.1 and 3.4 of National Policy 41-201 to treat CPRI, CPGPC and CPC Trust (and certain other subsidiaries) as subsidiaries of the Trust, or if accounting principles prohibit the consolidation of financial information, then to provide certain financial statements for the Trust's subsidiaries and the Trust will take appropriate measures to require each person who would be an insider to file insider reports about trades in Trust Units.

GENERAL DEVELOPMENT OF THE BUSINESS OF THE TRUST

History

The following is a description of the general development of the business of the Trust and of Crescent Point over the past three years.

2005

On March 31, 2005, Crescent Point Energy Partnership and the Limited Partnership completed the acquisition of certain oil and gas properties from an Alberta based oil and gas corporation, with an effective date of February 1, 2005. The properties are focused in the Storthoaks, Ingoldsby and Manor areas of southeast Saskatchewan. Crescent Point Energy Partnership and the Limited Partnership paid \$18 million in cash for the properties. The purchase price was financed by a draw down from our credit facility.

On April 21, 2005, we completed a public offering of 3,930,000 Trust Units at a price of \$19.10 per Trust Unit, for gross proceeds of \$75.06 million. We used the net proceeds of the issue for the acquisition of the Red Springs property, to reduce bank indebtedness and for general corporate and trust purposes.

On May 6, 2005, CPRL completed the acquisition of certain oil and gas properties from an Alberta based oil and gas corporation, with an effective date of January 1, 2005. The properties are focused in the Redsprings area of Alberta, which is located adjacent to the Trust's core John Lake property in Alberta. The Trust paid \$48 million in cash for the properties. The purchase price was financed out of proceeds from the Trust's public offering of 3,930,000 Trust Units on April 21, 2005.

On May 13, 2005, we announced the appointment of Mr. Peter Bannister as the Chairman of the board of directors of CPRL, replacing Paul Colborne. See "*Additional Information Respecting CPRI – Directors and Officers*".

On May 13, 2005, we announced the appointment of Mr. Ken Lamont as Controller and Treasurer of CPRL. See "*Additional Information Respecting CPRI – Directors and Officers*".

On June 22, 2005, the Limited Partnership completed the acquisition of certain oil and gas properties from an Alberta based oil and gas corporation, with an effective date of June 1, 2005. The properties are focused in the Ingoldsby area of Saskatchewan, which is located within the Trust's primary operating area in southeast Saskatchewan. The Limited Partnership paid \$28.5 million in cash for the properties. The purchase price was financed by a draw down from our credit facility.

On July 26, 2005, CPGPC completed the acquisition of certain oil and gas properties from a private consortium, with an effective date of May 1, 2005. The properties are focused in the Glen Ewen area of Saskatchewan, which is located within the Trust's operating area of Glen Ewen in southeast Saskatchewan. CPGPC paid \$47.75 million in cash for the properties. The purchase price was financed out of a treasury issuance of 2,000,000 Trust Units and a cash draw down from our credit facility in the amount of \$11.45 million.

On September 13, 2005, CPGPC completed the acquisition of certain oil and gas properties from an Alberta based oil and gas corporation. The properties are focused in the Tatagwa area of Saskatchewan, which is located within the Trust's core Tatagwa property in southeast Saskatchewan. CPGPC paid \$5.2 million in cash for the properties. The purchase price was financed out of a treasury issuance of 235,000 Trust Units and cash consideration of approximately \$650,000.

On September 14, 2005, we announced the appointment of Ms. Tamara MacDonald to Vice President, Land effective October 1, 2005. See "*Additional Information Respecting CPRI – Directors and Officers*".

On October 28, 2005, the Limited Partnership and CPGPC completed the acquisition of certain oil and gas properties from an Alberta based oil and gas corporation, with an effective date of September 1, 2005. The properties are focused in the Tatagwa, Weyburn and Minton areas of Saskatchewan, which is located within the Trust's core Tatagwa property in southeast Saskatchewan. The Limited Partnership and CPGPC paid \$37.75 million in cash for the properties. The purchase price was financed by a draw down from our credit facility.

On November 29, 2005, Crescent Point and Bulldog completed the Bulldog Arrangement as described below under the heading "*Description of Our Business - Reorganizations*".

On December 29, 2005, we completed a public offering of 10,406,000 Subscription Receipts at a price of \$21.15 per Subscription Receipt, for gross proceeds of approximately \$220.09 million. We used the net proceeds of the issue to partially finance the Cantuar/Batrum Acquisition (as defined below).

2006

On January 3, 2006, CPGPC and the Limited Partnership completed the acquisition of certain oil and gas properties from an Alberta based oil and gas trust, with an effective date of June 1, 2005. The properties are focused in the Rosebank area of Saskatchewan, which is located within the Trust's core operated southeast Saskatchewan group of properties. CPGPC and the Limited Partnership paid \$27.5 million in cash for the properties. The purchase price was financed by a draw down from our credit facility.

On January 9, 2006, CPGPC and the Limited Partnership completed the acquisition of certain oil and gas properties from an Alberta based oil and gas corporation, with an effective date of December 1, 2005 (the "Cantuar/Battrum Acquisition"). The properties are focused in the Cantuar and Battrum areas of southwestern Saskatchewan. CPGPC and the Limited Partnership paid \$257 million in cash for the properties. The purchase price was financed out of proceeds from the Trust's public offering of 10,406,000 Subscription Receipts on December 29, 2005 and a draw down from our credit facility. The Trust filed a Form 51-102F4 – Business Acquisition Report in respect of the acquisition on March 6, 2006.

On January 9, 2006, the 10,406,000 Subscription Receipts issued pursuant to the offering on December 29, 2005 were exchanged for an equal number of Trust Units.

On February 6, 2006, CPGPC and the Limited Partnership completed the acquisition of certain oil and gas properties from an Alberta based oil and gas corporation, with an effective date of January 1, 2006. These properties are focused largely in the Worsley area of northwestern Alberta. CPGPC and the Limited Partnership paid approximately \$55 million for the properties, comprised of \$11 million in cash and the issuance of 2,080,379 Trust Units. The cash portion of the purchase price was financed through a draw down from our credit facility.

On February 23, 2006 and March 1, 2006, the Trust completed two small, strategic acquisitions comprised of light oil and natural gas producing assets for a total consideration of approximately \$16 million. These two asset acquisitions further consolidated Crescent Point's Ingoldsby southeast Saskatchewan area for combined production of 370 boe/d. The acquisitions were funded through cash from the Trust's existing bank lines.

On December 30, 2005, January 31, 2006 and March 31, 2006, the Trust completed certain internal reorganization transactions including the Trust and certain of its subsidiaries. As a result of these transactions, all the material oil and gas assets of the Trust now reside in the Limited Partnership and Crescent Point Energy Partnership was wound up into the Limited Partnership.

On May 29, 2006, the Trust's bank syndicate increased the Trust's borrowing base from \$320 million to \$350 million, recognizing the Trust's reserves growth through acquisition and development.

On May 30, 2006, the Trust closed the acquisition of Canex pursuant to the Canex Arrangement for a total consideration of approximately \$85.6 million paid through a combination of Trust Units, cash and assumed debt. Production acquired by the Trust was approximately 975 boe/d of focused, high netback, light oil and natural gas located in the Trust's new Peace River Arch core area in northwest Alberta. For a further description of the Canex Arrangement. See "*Description of Our Business - Reorganizations*".

On June 9, 2006, 1171080 Alberta Ltd., 1186691 Alberta Ltd., Crescent Point General Partner Corp., 1211751 Alberta Ltd., 1223309 Alberta Ltd., 1223360 Alberta Ltd. and 1245931 Alberta Ltd. amalgamated to form Crescent Point General Partner Corp.

On June 9, 2006, 1079440 Alberta Ltd., CPRL and 1203531 Alberta Ltd. amalgamated to form CPRL.

On June 28, 2006, the Trust announced it has entered into four separate agreements to acquire 880 boe/d of oil and natural gas producing assets for a total consideration of \$61.6 million. The acquisitions added 4.1 million boe of proved plus probable and 3.1 million boe of proved reserves and further consolidated the Trust's core areas of southwest Saskatchewan, southeast Saskatchewan and John Lake, Alberta. The acquisitions were funded with cash from existing bank lines. All four agreements closed on or before August 1, 2006.

On June 28, 2006, the Trust also announced a bought deal equity financing of 4.7 million trust units at \$21.35 per Trust Unit for gross proceeds of approximately \$100 million. Closing of the financing occurred on July 20, 2006. The Trust used the net proceeds of the offering to reduce the Trust's outstanding indebtedness, and to further enhance the Trust's business strategy of acquiring long life, high quality reserves.

On September 12, 2006, the Trust exercised its redemption call right in respect of all of the issued and outstanding Exchangeable Shares. As a result, the Trust purchased all of the issued and outstanding Exchangeable Shares from the holders thereof on October 27, 2006. The redemption price for such Exchangeable Shares was satisfied by the delivery to each Exchangeable Shareholder of 1.46210 Trust Units for each Exchangeable Share held, less any amount withheld on account of tax required to be deducted or withheld therefrom.

On November 22, 2006, the Trust's bank syndicate increased the Trust's borrowing base from \$350 million to \$470 million.

On December 31, 2006, CPGPC and CPRL amalgamated to form Crescent Point General Partner Corp.

2007

On February 9, 2007, the Trust and Mission completed the Mission Arrangement for a total consideration of approximately \$574.1 million paid through a combination of Trust Units, cash and assumed debt. The acquisition adds 24.8 million boe of proved plus probable and 15.9 million boe of proved reserves and further consolidates the Trust's core areas of southeast Saskatchewan. See "*Description of Our Business - Reorganizations*".

On March 1, 2007, the Trust completed an internal reorganization involving the Trust and certain of its subsidiaries. As a result of the reorganization and the subsequent dissolution of Mission Oil & Gas Limited Partnership on March 2, 2007, all of the material oil and gas assets of the Trust now rest in the Limited Partnership. CPRI became the administrator of the Trust and certain subsidiaries of the Trust were dissolved or amalgamated pursuant to the internal reorganization. See "*Description of our Business – Reorganization*".

On May 28, 2007, the Trust's bank syndicate increased the Trust's borrowing base from \$470 million to \$600 million, recognizing the Trust's reserves growth through acquisition and development.

On June 22, 2007, new legislation was passed (the "SIFT Rules") pursuant to which, certain distributions from specified investment flow-through trusts and partnerships ("SIFTS"), such as the Trust, will be subject to a trust-level tax, and will be characterized as dividends to the Unitholders, commencing January 1, 2011 (provided that the Trust experiences only "normal growth" and no "undue expansion" before then). See "*Risk Factors – Income Tax Matters*".

On September 5, 2007, the Trust announced a bought deal equity financing of 8.9 million trust units at \$18.55 per Trust Unit for gross proceeds of approximately \$165 million. Closing of the financing occurred on September 25, 2007. The Trust used the net proceeds of the offering to reduce the Trust's outstanding indebtedness incurred prior to the October 31, 2006 federal government announcement on income trust taxation.

On September 5, 2007, the Trust announced the strategic Bakken consolidation acquisition of Innova for \$7.55 cash per Innova share, plus assumed debt, for a total consideration of approximately \$400 million. The Trust subsequently took effective control of Innova on October 22, 2007. With the completion of the acquisition, the Trust acquired approximately 4,300 boe/d of high quality, high netback light oil and natural gas production, more than 97 net sections of undeveloped Bakken land, and 380 net low risk Bakken development drilling locations.

In late October 2007, as part of the acquisition of Innova, the Trust's bank syndicate increased the borrowing base from \$600 million to \$800 million, recognizing the strong reserves growth through continued development and acquisition success as well as the stability of the Trust's continued risk management activities.

2008

On January 8, 2008, the Trust announced the closing of its equity offering of 5,155,000 trust units at \$24.25 per trust unit for aggregate gross proceeds of \$125 million.

On January 16, 2008, the Trust completed the acquisition of Pilot by way of plan of arrangement, through its wholly-owned subsidiary CPGPC, for total consideration of approximately \$76 million paid through the issuance of 0.1284 of a Trust Unit for each issued and outstanding Pilot common share. The acquisition extended the Trust's Bakken play in southeast Saskatchewan, increasing the Trust's production to more than 12,500 boe/d in the area. See "*Description of Our Business - Reorganizations*".

On March 26, 2008, the Trust announced the completion of a \$120 million commitment to Shelter Bay, a private Bakken light oil growth company, in association with Shelter Bay's closing of a \$625 million private placement. The Trust also announced the related closing of a plan of arrangement with Landex Petroleum Corporation ("Landex"), pursuant to which Shelter Bay acquired Landex in exchange for total consideration of approximately \$310 million, including approximately \$75 million in trust units. Following the closing of the arrangement with Landex, the Trust acquired Landex's non-Bakken assets from Shelter Bay for \$80 million. Shelter Bay is managed by CPGPC pursuant to a management and technical services agreement and its business model will be to develop, exploit and acquire light oil and natural gas properties in western Canada. Through the Trust's equity investment in Shelter Bay, it has the right to 50% of Shelter Bay's returns above a minimum threshold. The Trust also has certain contingent rights to acquire the shares of Shelter Bay, or Shelter Bay's assets, before December 31, 2012 and certain other shareholders of Shelter Bay have the right to sell their interests in Shelter Bay to the Trust from January 1, 2013 to June 30, 2013.

DESCRIPTION OF OUR BUSINESS

General

The principal undertakings of the Trust are to issue Trust Units and to acquire and hold debt and other investment interests. Our direct and indirect wholly-owned subsidiaries carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto. The primary assets of the Trust are currently the shares in CPRI and CPEL, units and debt in CPC Trust and units in the Limited Partnership. In addition, we continually review and assess numerous corporate and asset acquisition opportunities as part of our ongoing acquisition program.

The crude oil and natural gas properties and related assets generating income for the benefit of the Trust are located in the provinces of Alberta, Saskatchewan, British Columbia and Manitoba. The properties and assets consist of producing crude oil and natural gas reserves and proven plus probable crude oil and natural gas reserves not yet on production.

We make monthly cash distributions to Unitholders from our net cash flow. Our primary sources of cash flow are distributions from the Limited Partnership and CPC Trust and interest payments from CPC Trust.

Strategy

We strive to create sustainable, value-added growth in reserves, production and cash flow through the execution of management's integrated strategy of acquiring, exploiting and developing high quality, long life, light oil and natural gas properties.

We continually investigate and search out producing properties that will result in meaningful reserve and production additions. We focus capital on higher-quality, longer-life reservoirs in proven growth areas that offer existing infrastructure, low cost drilling, multi-zone potential and year round access. Our goal is to acquire operational control of those properties that we believe offer significant exploitation and development potential.

We develop our properties through a detailed technical analysis of information including reservoir characteristics, original oil or gas in place, recovery factors and the applicability of enhanced recovery techniques. Our goal is to increase reserves and production in a cost effective manner through a number of techniques, including drilling infill and step-out wells, re-completing existing wells and implementing waterflood or pressure support schemes.

Risk Management and Marketing

Factors outside our control impact, to varying degrees, the prices we receive for production and the associated operating expenses we incur. These include but are not limited to:

- (a) world market forces, including the ability of the OPEC to set and maintain production levels and prices for crude oil;
- (b) political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;
- (c) increases or decreases in crude oil quality differentials and their implications for prices received by us;
- (d) the impact of changes in the exchange rate between Canadian and U.S. dollars on prices received by us for our crude oil and natural gas;
- (e) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
- (f) global and domestic economic and weather conditions;
- (g) price and availability of alternative fuels; and
- (h) the effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside of our control and yet can have a significant impact on the level of cash we have available for distribution to Unitholders.

To mitigate a portion of these risks, we actively initiate, manage and disclose the effects of our hedging activities. Our strategy for crude oil and natural gas production is to hedge up to 65% of our existing production, after crown royalties, on a rolling three and a half year basis, at the

discretion of management. All hedging activities are governed by a Risk Management Policy and are regularly reviewed by the board of directors of CPRI.

As part of our risk-management strategy in 2007, total oil and gas hedged was approximately 51% of annual production, net of royalties, of which approximately 56% of annual crude oil production and approximately 16% of annual natural gas production was hedged, net of royalties. The hedging strategies we utilized included only financial instruments, with our primary objective being to enhance the stability of cash distributions. The following table summarizes our commitments under all hedging agreements as at March 3, 2008.

Financial WTI Crude Oil Contracts – Canadian Dollar

<u>Term</u>	<u>Volume (bbls/d)</u>	<u>Average Swap Price (\$Cdn/bbl)</u>	<u>Average Bought Put Price (\$Cdn/bbl)</u>	<u>Average Sold Call Price (\$Cdn/bbl)</u>	<u>Average Put Premium (\$Cdn/bbl)</u>
2008 Weighted Average	16,521	78.48	72.85	88.44	(6.66)
2009 Weighted Average	16,000	79.28	71.78	86.20	(6.03)
2010 Weighted Average	11,561	80.99	75.48	90.54	(4.56)
January 1 to June 30, 2011 Weighted Average	500	96.20	-	-	-

Financial AECO Natural Gas Contracts – Canadian Dollar

<u>Term</u>	<u>Volume (GJ/d)</u>	<u>Average Swap Price (\$Cdn/GJ)</u>	<u>Average Bought Put Price (\$Cdn/GJ)</u>	<u>Average Sold Call Price (\$Cdn/GJ)</u>
January 1, 2008 to October 31, 2008 Weighted Average	2,000	-	6.75	7.82

Financial Interest Rate Contracts – Canadian Dollar

<u>Term</u>	<u>Contract</u>	<u>Principal (\$Cdn)</u>	<u>Fixed Annual Rate (%)</u>
January 2008 to May 2008	Swap	50,000,000	4.41
January 2008 to February 2009	Swap	50,000,000	4.37
January 2008 to November 2010	Swap	75,000,000	4.35

Beyond the hedging strategy, we also mitigate risk by having a well diversified marketing portfolio for oil and natural gas by transacting with a number of counterparties to limit our exposure to any one counterparty. The majority of our oil and natural gas volumes are sold into the Alberta, British Columbia and Saskatchewan index priced markets with terms of one year or less. Approximately 88% of our oil volumes are sold into the Saskatchewan market and 12% into the Alberta market. Approximately 74% of our natural gas volumes are sold into the Alberta market, 18% into the Saskatchewan market and 8% into the British Columbia market.

In addition to these noted risk-management practices, a portion of our portfolio of assets consists of natural gas reserves. Because oil and gas price cycles do not necessarily coincide, such a balance often provides a natural mitigation of price risk.

For 2007, our commodity mix was approximately 87% oil and NGLs and 13% natural gas. We realized hedge losses of approximately \$9.9 million in 2007.

Revenue Sources

For the year ended December 31, 2007, 8% of the revenue from our properties before hedging and royalties was derived from natural gas and 92% from crude oil and natural gas liquids.

For the year ended December 31, 2006, 11% of the revenue from our properties before hedging and royalties was derived from natural gas and 89% from crude oil and natural gas liquids.

For the year ended December 31, 2005, 22% of the revenue from our properties before hedging and royalties was derived from natural gas and 78% from crude oil and natural gas liquids.

Competition

We actively compete for capital reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than we do. Our competitors include major integrated oil and natural gas companies, numerous other independent oil and natural gas companies and trusts and individual producers and operators.

Certain of our customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect our ability to sell or supply oil or gas to these customers in the future. Our ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with our industry partners and joint operators and our ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Seasonal Factors

The development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

Personnel

As at December 31, 2007, we had 99 full-time employees, 14 part-time employees and 8 consultants at our head office. In the field we had 65 full-time field staff and 1 part-time field staff, and 39 consultants.

Reorganizations

On September 5, 2003, we completed the Arrangement whereby holders of Class A Shares and Class B Shares of Crescent Point Energy Ltd. and holders of common shares (collectively the "Shares") of Tappit Resources Ltd. ("Tappit") elected, or were deemed to have elected, to receive either Trust Units or Exchangeable Shares for their Shares on the basis 0.50, 0.75 and 0.19 of a Trust Unit or Exchangeable Share, respectively, for each Share held. Tappit shareholders also received cash in the amount of \$0.36 per Tappit common share. Concurrent with the Arrangement becoming effective, Crescent Point's exploration assets were acquired by StarPoint Energy Ltd. ("StarPoint") and the common shares of StarPoint were distributed to the former holders of Shares on the basis of 0.50, 0.75 and 0.10 of a common share of StarPoint, respectively, for each such Share held.

On November 29, 2005, we completed the Bulldog Arrangement whereby we acquired all of Bulldog's issued and outstanding Class A and Class B Shares in exchange for Trust Units of the Trust. Bulldog Class A shares were exchanged for 0.13 of a Trust Unit. Concurrent with the Arrangement, each issued and outstanding Class B share was converted into a Class A share and the Class A shares were then exchanged for Trust Units of the Trust in accordance with the above mentioned exchange ratios. In addition, Bulldog shareholders were entitled to receive one common share of Bulldog Resources Inc. for each Bulldog Class A share held.

On December 30, 2005, January 31, 2006 and March 31, 2006, the Trust completed certain internal reorganization transactions including the Trust and certain of its subsidiaries. As a result of these transactions, all the material oil and gas assets of the Trust rested in the Limited Partnership and Crescent Point Energy Partnership was wound up into the Limited Partnership.

On May 30, 2006, we completed the Canex Arrangement whereby we acquired all of Canex's issued and outstanding common shares in exchange for Trust Units. Concurrent with the Arrangement, each issued and outstanding Canex share was exchanged for 0.1003 of a Trust Unit and \$0.5876 in cash. Canex shareholders received 1.0 common share and one-third of a common share purchase warrant of Canext Energy Ltd. for each Canex share held. In addition, certain electing shareholders were entitled to receive 0.1003 of a Trust Unit, \$0.4209 in cash, and two-thirds of a common share in Canext Energy Ltd. for each Canex share held.

On February 9, 2007, we completed the Mission Arrangement whereby we acquired all of Mission's issued and outstanding common shares in exchange for Trust Units and cash. Mission shares were exchanged for 0.695 trust units plus cash in the amount of \$0.78 per Mission common share.

On March 1, 2007, the Trust completed an internal reorganization involving the Trust and certain of its subsidiaries. As a result of this and the reorganization and the subsequent dissolution of Mission Oil & Gas Limited Partnership on March 2, 2007, all of the material oil and gas assets of the Trust rest in the Limited Partnership.

On September 5, 2007, the Trust announced the strategic Bakken consolidation acquisition of Innova for \$7.55 cash per Innova share, plus assumed debt, for a total consideration of approximately \$400 million. The Trust subsequently took effective control of Innova on October 22, 2007 when more than 97 percent of outstanding Innova shares were tendered to the offer. With the completion of the acquisition, the Trust

acquired approximately 4,300 boe/d of high quality, high netback light oil and natural gas production, more than 97 net sections of undeveloped Bakken land, and 380 net low risk Bakken development drilling locations.

On January 16, 2008, the Trust completed the acquisition of Pilot by way of plan of arrangement, through its wholly-owned subsidiary CPGPC for total consideration of approximately \$76 million paid through the issuance of 0.1284 of a Trust Unit for each issued and outstanding Pilot common share. The acquisition extends the Trust's Bakken play in southeast Saskatchewan, increasing the Trust's production to more than 12,500 boe/d in the area.

As a result of internal reorganization steps taken subsequent to the acquisitions of Innova and Pilot, all of the material oil and gas assets of the Trust continue to rest in the Limited Partnership.

Social and Environmental Policies

During the second quarter of 2004, we established a reclamation fund to provide for future asset retirement costs. Effective July 1, 2004 through March 31, 2005, we contributed \$0.15 per barrel of production, as well as a lump-sum contribution in the amount of \$250,000, to the reclamation fund. From April 1, 2005 to December 31, 2005, we contributed \$0.20 per barrel of production, as well as lump-sum contributions in the amount of \$200,000 to the reclamation fund. From January 1, 2006 to December 31, 2006, we contributed \$0.20 per barrel of production, as well as lump-sum contributions of \$1,000,000. From January 1, 2007 to December 31, 2007, we contributed \$0.25 per barrel of production.

Additionally, contributions are made at the discretion of management. Contributions to the reclamation fund and interest earned on the reclamation fund balance have been deducted from the cash distribution to the Unitholders and cash withheld to fund current period capital expenditures and repay bank indebtedness.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

THE TRUST

Disclosure of Reserves Data

In accordance with NI 51-101, the reserves data of Crescent Point Energy Trust set forth below (the "Reserves Data") is based upon evaluations by GLJ and Sproule with an effective date of December 31, 2007 contained in the consolidated report of GLJ dated March 7, 2008 (the "Crescent Point Energy Trust Engineering Report"). The Crescent Point Energy Trust Engineering Report evaluated, as at December 31, 2007, our crude oil, NGL and natural gas reserves, which excludes the oil, NGL and natural gas reserves acquired pursuant to the acquisition of Pilot, as this acquisition was completed in 2008. The tables below are a combined summary of our crude oil, NGL and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Crescent Point Energy Trust Engineering Report based on GLJ's January 1, 2008 forecast price and cost assumptions. GLJ evaluated approximately 34 percent of the assigned total proved plus probable reserves and 32 percent of the total proved plus probable value discounted at 10 percent. Sproule evaluated approximately 66 percent of the assigned total proved plus probable reserves and 68 percent of the total proved plus probable value discounted at 10 percent. Sproule evaluated our Bakken properties in southeast Saskatchewan and our Cantuar and Battrum properties in southwest Saskatchewan. They had prepared a similar engineering report for the previous year. Sproule incorporated the GLJ forecast price and cost assumptions in their evaluation. GLJ prepared the Crescent Point Energy Trust Engineering Report by consolidating the GLJ evaluation with the Sproule evaluation, all run on the GLJ pricing and cost assumptions. The tables summarize the data contained in the Crescent Point Energy Trust Engineering Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to our reserves is stated without provision for interest costs, income taxes and general and administrative costs, but after providing for estimated royalties, production costs, capital taxes, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by GLJ and Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to our reserves estimated by GLJ and Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of our 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 reserves may be greater than or less than the estimates provided herein.

The Crescent Point Energy Trust Engineering Report is based on certain factual data supplied by us and GLJ and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to our petroleum properties and contracts (except for certain information residing in the public domain) were supplied by us to GLJ and Sproule, and were accepted without any further investigation. GLJ and Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves

	Gross Reserves					Net Reserves				
	Light and Medium Crude Oil (Mbbbls)	Heavy Crude Oil (Mbbbls)	NGLs (Mbbbls)	Natural Gas (MMcf)	Total (Mboe)	Light and Medium Crude Oil (Mbbbls)	Heavy Crude Oil (Mbbbls)	NGLs (Mbbbls)	Natural Gas (MMcf)	Total (Mboe)
Proved										
Developed Producing	60,730	1,358	1,611	43,262	70,910	51,652	1,293	1,425	35,429	60,274
Developed Non-Producing	1,673	415	257	6,275	3,392	1,475	393	206	4,531	2,829
Undeveloped	35,262	180	2,794	18,989	41,401	31,712	161	2,594	16,313	37,186
Total Proved	97,666	1,954	4,662	68,526	115,703	84,838	1,847	4,224	56,273	100,289
Probable	44,388	613	2,164	27,648	51,773	38,598	576	1,985	22,908	44,977
Total Proved plus Probable	142,054	2,566	6,826	96,175	167,476	123,436	2,423	6,210	79,181	145,266

Net Present Value of Future Net Revenue of Oil and Gas Reserves

	Before Income Tax Expenses and Discounted at					Unit Value Before Income Tax Discounted at 10%	
	0%	5%	10%	15%	20%		
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(\$/boe)	(\$/Mcfje)
Proved							
Developed Producing	2,812,839	2,082,080	1,695,324	1,452,326	1,283,259	28.13	4.69
Developed Non-Producing	116,714	80,737	62,247	50,900	43,135	22.00	3.67
Undeveloped	1,819,227	1,326,071	1,026,388	827,378	686,399	27.60	4.60
Total Proved	4,748,780	3,488,888	2,783,958	2,330,605	2,012,793	27.76	4.63
Probable	2,492,837	1,346,743	874,942	630,480	483,675	19.45	3.24
Total Proved plus Probable	7,241,617	4,835,631	3,658,901	2,961,084	2,496,468	25.19	4.20

	After Income Tax Expenses and Discounted at					Unit Value Before Income Tax Discounted at 10%	
	0%	5%	10%	15%	20%		
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(\$/boe)	(\$/Mcfje)
Proved							
Developed Producing	2,630,828	1,987,669	1,638,386	1,414,651	1,256,721	27.18	4.53
Developed Non-Producing	95,566	68,172	53,792	44,779	38,492	19.01	3.17
Undeveloped	1,597,954	1,188,667	933,706	760,970	636,660	25.11	4.18
Total Proved	4,324,348	3,244,508	2,625,884	2,220,400	1,931,872	26.18	4.36
Probable	1,854,205	1,020,979	674,088	492,498	382,477	14.99	2.50
Total Proved plus Probable	6,178,553	4,265,487	3,299,972	2,712,898	2,314,349	22.72	3.79

Additional Information Concerning Future Net Revenue – (Undiscounted)

	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Abandonment and Reclamation Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Tax (M\$)	Future Net Revenue After Income Taxes (M\$)
Total Proved	8,668,750	1,282,810	1,840,534	719,563	77,063	4,748,780	424,432	4,324,348
Total Proved plus Probable	13,021,527	1,908,669	2,847,036	929,024	95,181	7,241,617	1,063,064	6,178,553

Future Net Revenue by Production Group ⁽¹⁾

		Future Net Revenue Before Income Taxes (Discounted at 10%)	Unit Value	
		(M\$)	(\$/ boe)	(\$/Mcf)
Proved	Light and Medium Crude Oil	2,684,032	28.33	4.72
	Heavy Crude Oil	37,717	18.60	3.10
	Natural Gas	62,209	17.73	2.96
	Total	2,783,958	27.76	4.63

		Future Net Revenue Before Income Taxes (Discounted at 10%)	Unit Value	
		(M\$)	(\$/ boe)	(\$/Mcf)
Proved Plus Probable	Light and Medium Crude Oil	3,534,019	25.61	4.27
	Heavy Crude Oil	46,644	17.56	2.93
	Natural Gas	78,238	17.01	2.84
	Total	3,658,901	25.19	4.20

Note:

(1) Light, medium and heavy oil include solution gas and other by-products. Natural gas includes by-products but excludes solution gas.

For future net revenue of the total proved reserves, discounted at 10 percent, 96.4% of the revenue is from the light and medium oil, 2.2% from natural gas, and 1.4% from heavy oil. For the total proved plus probable reserves, 96.6% of the revenue is from the light and medium oil, 2.1% from natural gas, and 1.3% from heavy oil.

Notes and Definitions

In the tables set forth above in “Disclosure of Reserves Data” and elsewhere in this Annual Information Form, the following notes and other definitions are applicable.

Reserve Categories

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

- (a) **“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, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.
- (b) **“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.
- (c) **“Developed Producing”** reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- (d) **“Developed Non-Producing”** reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (e) **“Undeveloped”** reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In

multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

- (f) **"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.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- At least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- At least a 50% 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 estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be 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.

Additional Definitions

The following terms, used in the preparation of the Crescent Point Energy Trust Engineering Report (as defined herein) and this Annual Information Form, have the following meanings:

- (a) **"associated gas"** means the gas cap overlying a crude oil accumulation in a reservoir.
- (b) **"crude oil"** or **"oil"** means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that are recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.
- (c) **"development costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
- (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
 - (ii) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
 - (iii) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
 - (iv) provide improved recovery systems.
- (d) **"development well"** means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
- (e) **"exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property

(sometimes referred to in part as “prospecting costs”) and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
 - (ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
 - (iii) dry hole contributions and bottom hole contributions;
 - (iv) costs of drilling and equipping exploratory wells; and
 - (v) costs of drilling exploratory type stratigraphic test wells.
- (f) **“exploratory well”** means a well that is not a development well, a service well or a stratigraphic test well.
- (g) **“F&D costs”** means finding and development costs.
- (h) **“field”** means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to denote localized geological features, in contrast to broader terms such as “basin”, “trend”, “province”, “play” or “area of interest”.
- (i) **“future prices and costs”** means future prices and costs that are:
- (i) generally accepted as being a reasonable outlook of the future;
 - (ii) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Trust is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (i).
- (j) **“future income tax expenses”** means future income tax expenses estimated (generally, year-by-year):
- (i) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
 - (ii) without deducting estimated future costs that are not deductible in computing taxable income;
 - (iii) taking into account estimated tax credits and allowances (for example, royalty tax credits); and
 - (iv) applying to the future pre-tax net cash flows relating to the Trust’s oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.
- (k) **“future net revenue”** means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using forecast prices and costs.
- (l) **“gross”** means:
- (i) in relation to the Trust’s interest in production or reserves, its “company gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Trust;
 - (ii) in relation to wells, the total number of wells in which the Trust has an interest; and
 - (iii) in relation to properties, the total area of properties in which the Trust has an interest.

- (m) “**natural gas**” means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.
- (n) “**natural gas liquids**” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.
- (o) “**net**” means:
- (i) in relation to the Trust’s interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
 - (ii) in relation to the Trust’s interest in wells, the number of wells obtained by aggregating the Trust’s working interest in each of its gross wells; and
 - (iii) in relation to the Trust’s interest in a property, the total area in which the Trust has an interest multiplied by the working interest owned by the Trust.
- (p) “**non-associated gas**” means an accumulation of natural gas in a reservoir where there is no crude oil.
- (q) “**operating costs**” or “**production costs**” means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.
- (r) “**production**” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.
- (s) “**property**” includes:
- (i) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
 - (ii) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
 - (iii) an agreement with a foreign government or authority under which the Trust participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).
- A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.
- (t) “**property acquisition costs**” means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:
- (i) costs of lease bonuses and options to purchase or lease a property;
 - (ii) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and
 - (iii) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.
- (u) “**proved property**” means a property or part of a property to which reserves have been specifically attributed.
- (v) “**reservoir**” means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
- (w) “**service well**” means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

- (x) “**solution gas**” means natural gas dissolved in crude oil.
- (y) “**stratigraphic test well**” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) “exploratory type” if not drilled into a proved property; or (ii) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.
- (z) “**support equipment and facilities**” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.
- (aa) “**unproved property**” means a property or part of a property to which no reserves have been specifically attributed.
- (bb) “**well abandonment costs**” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

Pricing Assumptions – Forecast Prices and Costs

GLJ and Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2007 in estimating our reserves data using forecast prices and costs.

Year	Natural Gas		Crude Oil		NGLs			Inflation Rate (%/yr)	Exchange Rate (\$US/\$Cdn)
	MidWest Price @ Chicago (\$US/MMBTU)	Spot Plant Gate (\$Cdn/MMBTU)	WTI at Cushing Oklahoma (\$US/bbl)	Edmonton (\$Cdn/bbl)	Pentanes Plus Edmonton (\$Cdn/bbl)	Butanes Edmonton (\$Cdn/bbl)	Propane Edmonton (\$Cdn/bbl)		
Forecast									
2008	7.40	6.53	92.00	91.10	92.92	72.88	58.30	2.0	1.000
2009	8.20	7.33	88.00	87.10	88.84	69.68	55.74	2.0	1.000
2010	8.25	7.37	84.00	83.10	84.76	66.48	53.18	2.0	1.000
2011	8.35	7.37	82.00	81.10	82.72	64.88	51.90	2.0	1.000
2012	8.35	7.37	82.00	81.10	82.72	64.88	51.90	2.0	1.000
2013	8.35	7.37	82.00	81.10	82.72	64.88	51.90	2.0	1.000
2014	8.55	7.57	82.00	81.10	82.72	64.88	51.90	2.0	1.000
2015	8.72	7.74	82.00	81.10	82.72	64.88	51.90	2.0	1.000
2016	8.89	7.91	82.02	81.12	82.74	64.89	51.91	2.0	1.000
2017	9.06	8.08	83.66	82.76	84.42	66.21	52.97	2.0	1.000
2018	9.24	8.24	85.33	84.42	86.11	67.53	54.03	2.0	1.000
2019+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	1.000

The weighted average realized sales prices before hedging for the year ended December 31, 2007 were \$6.52/Mcf for natural gas, and \$67.33/bbl for crude oil and NGLs.

Reconciliations of Changes in Reserves and Future Net Revenue

Reserves Reconciliation

The following table sets forth a reconciliation of the Trust's Total Working Interest reserves by total proved, probable and total proved plus probable reserves as at December 31, 2007 against such reserves as at January 1, 2007 based on forecast price and cost assumptions.

Factors	Crude Oil and Liquids			Natural Gas			Oil Equivalent		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)
January 1, 2007	57,458	23,962	81,420	38,959	14,446	53,405	63,951	26,370	90,321
Extensions	21,165	14,673	35,837	8,748	5,328	14,076	22,623	15,561	38,183
Infill Drilling	1,873	40	1,914	1,294	190	1,484	2,089	72	2,161
Improved Recovery	432	228	660	0	0	0	432	228	660
Technical Revisions	1,561	(850)	712	3,068	(2,376)	691	2,072	(1,246)	827
Discoveries	38	12	51	5	2	8	39	13	52
Acquisitions	30,554	9,099	39,653	25,797	10,542	36,339	34,854	10,856	45,711
Dispositions	(32)	(34)	(66)	(1,197)	(522)	(1,719)	(232)	(121)	(353)
Economic Factors	119	34	153	105	39	144	137	40	177
Production	(8,887)	0	(8,887)	(8,253)	0	(8,253)	(10,263)	0	(10,263)
December 31, 2007	104,282	47,164	151,446	68,526	27,649	96,175	115,703	51,773	167,476

Note:

- (1) The Trust has no unconventional reserves (Bitumen, Synthetic Crude Oil, Natural Gas from Coal, Natural Gas from Hydrates, Shale Oil, and Shale Gas, etc.).

Undeveloped Reserves

The following discussion generally describes the basis on which we attribute proved and probable undeveloped reserves. Our plans for developing our undeveloped reserves are described in the section "Major Oil and Gas Properties".

Proved Undeveloped Reserves

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two year timeframe. The following table provides the timing of the initial reserve assignments for the Trust's proved undeveloped gross reserves.

Timing of Initial Proved Undeveloped Reserve Assignment

Product Type	Units	Company Gross Reserves First Attributed by Year				
		Prior	2005	2006	2007	Total
Proved Undeveloped						
Light and Medium Oil	Mbbl	1,021	1,892	3,173	29,176	35,262
Heavy Oil	Mbbl	45	40	0	95	180
Natural Gas	MMcf	835	725	1,677	15,752	18,989
Natural Gas Liquids	Mbbl	9	46	54	2,685	2,794
Oil Equivalent	Mboe	1,215	2,098	3,507	34,581	41,401

Probable Undeveloped Reserves

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a two year timeframe. The following table provides the timing of the initial reserve assignments for the Trust's probable undeveloped gross reserves.

Timing of Initial Probable Undeveloped Reserves Assignment

Product Type	Units	Company Gross Reserves First Attributed by Year				
		Prior	2005	2006	2007	Total
Probable Undeveloped						
Light and Medium Oil	Mbbl	518	1,656	3,511	16,916	22,601
Heavy Oil	Mbbl	12	10	50	24	96
Natural Gas	MMcf	527	469	1,027	7,912	9,936
Natural Gas Liquids	Mbbl	5	39	36	1,342	1,422
Oil Equivalent	Mboe	622	1,783	3,768	19,601	25,774

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Our reserves are evaluated by GLJ and Sproule, each an independent engineering firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

	Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
	(M\$)	(M\$)
2008	243,216	273,373
2009	230,318	246,304
2010	164,601	215,874
2011	40,371	135,276
2012	25,492	38,346
Remaining Years	15,565	19,851
Total Undiscounted	719,563	929,024

We estimate that our internally generated cash flow will be sufficient to fund the future development costs disclosed above. We typically have available three sources of funding to finance our capital expenditure program; internally generated cash flow from operations, debt financing when appropriate and new equity issues (including proceeds from our distribution reinvestment plans), if available on favourable terms. Debt financing is available to us at market rate plus an applicable margin based on our debt to cash flow ratio. The current rate available to us under prime loan drawdowns is 5.25% per annum.

We expect to fund our total 2008 capital program with internally generated cash flow and although quarterly fluctuations in funding levels are expected, our objective is to reduce our current net debt level throughout 2008. Our objective is to maintain our net debt to cash flow ratio at 1.0 times estimated future annual cash flows.

Major Oil and Gas Properties

The following is a description of the company's major oil and natural gas properties, plants, facilities and installations in which we have an interest and that are material to our operations and activities. The production numbers stated refer to our working interest share before deduction of Crown and freehold royalties. Unless otherwise stated, reserve amounts are stated before deduction of royalties, based on escalating cost and price assumptions as evaluated in the GLJ and Sproule Reports as at December 31, 2007.

Viewfield Bakken

During 2007, Crescent Point established, consolidated and expanded a dominant position in the southeast Saskatchewan Bakken light oil resource play. The Trust completed five acquisitions in the Viewfield Bakken play, including the February acquisition of Mission and the October acquisition of Innova. The Trust also aggressively expanded the play with a successful step out exploration drilling program and a strategic land acquisition strategy that added 115 net sections of undeveloped land, the Trust's Bakken land holdings totalled 413 net sections by year end.

Crescent Point is now the largest oil producer in southeast Saskatchewan. The Trust is also the dominant player in the Viewfield Bakken play due to its production levels, drilling inventory, infrastructure control and undeveloped land holdings. Year end 2007 production from the Bakken area exceeded 12,000 boe/d, the largest in the southeast Saskatchewan Bakken play. By February of 2008, over 300 gross wells had been drilled on Trust owned lands in the Bakken and a 100 percent success rate, providing Crescent Point with the largest database of economic and technical Bakken data. The Trust operates the largest and most centrally located gas plant and gathering system in the play, providing a significant competitive advantage. This area dominance provides the Trust with economies of scale and influence over the cost and availability of supplies and services.

Crescent Point engineers and field staff continue to improve the fracture stimulation techniques utilized in the Bakken to improve the productivity of the horizontal oil wells and to better unlock the value of the play. Technological advances have more than doubled initial production rates, significantly increased per well reserves and more than tripled per well values.

In 2007, the Trust drilled a total of 88 (60.0 net) Bakken horizontal wells, including 11 step out exploration wells, and fracture stimulated 46 (38.3 net) Bakken horizontal wells. Utilizing a series of improvements to the fracture stimulation technology, the Trust increased average initial post fracture stimulation production rates to more than 200 boe/d per well.

As a result of the Trust's activities in the area, independent engineers recognized at year end 2007 positive technical and development reserve revisions of 35.7 mmmboe proved plus probable and 20.8 mmmboe proved on these lands. Crescent Point believes that infill drilling over time may increase recovery factors to 15 percent compared to the 3.9 percent currently booked by independent engineers. This increase could add upwards of 190 mmmboe of proved plus probable reserves net to the Trust in the Bakken play.

The Trust has internally identified 1,210 (1,050.0 net) drilling locations on its Bakken land holdings with a risked production potential of more than 85,000 boe/d. The Trust has a fracture stimulation inventory of 65 (60.0 net) previously fracture stimulated wells and a further 75 (70.0 net) wells that have not yet been fracture stimulated. In all, the Trust could add up to 13,000 boe/d of net incremental production from fracture stimulation activities.

The Trust's large drilling inventory, along with strategic decisions regarding the timing of fracture stimulation programs, provides the Trust with significant flexibility in the implementation of its capital development activities.

During 2008, Crescent Point plans to drill up to 79 (65.5 net) horizontal wells in the Bakken and fracture stimulate 92 (77.2 net) wells. Due to successful exploration and exploitation activities in the Bakken, the Trust doubled the capacity of the Viewfield gas plant from 3 mmcf/d to 6 mmcf/d in 2007 and added full fractionalized facilities. The Trust will further expand the plan to 15 mmcf/d in late 2008, which will accommodate the Trust's successful Bakken drilling and fracture stimulation activities. Crescent Point also operates 17 oil batteries in the Bakken area, providing further operational flexibility and control.

Battrum

In the Battrum area, the Trust continued to optimize reserves recoveries through a combination of water flood optimization, infill drilling and recompletions. Positive reserve revisions of 1.2 mmmboe proved plus probable were assigned by independent engineers. The trust drilled 8 (3.6 net) wells at Battrum with a 100 percent success rate and added over 180 boe/d of interest production. Since acquiring the property in 2006, the Trust has added over 8.3 mmmboe of proved plus probable reserves to a total of 13.9 mmmboe at year end 2007.

In 2008, the Trust plans to drill up to 15 (6.3 net) oil wells at Battrum.

Cantuar

At the non operated Cantuar Unit, a reservoir simulation model demonstrated the OOIP estimates and increased from 409 mmbbls to 489 mmbbls, the result of infill drilling and improved water flood performance accessing more of the reservoir. Positive reserve revisions of 0.9 mmmboe proved plus probable were assigned by independent engineers.

The Trust participated in the drilling of 5 (2.8 net) wells at Cantuar, including two 20 acre downspaced wells, achieving a 100 percent success rate, and adding over 80 boe/d of interest production. Up to 5 (2.8 net) 20 acre spaced wells are planned for 2008. Since acquiring the property in 2006, the Trust has added over 8.5 mmboe of proved plus probable reserves to a total of 18.4 mmboe at year end 2007.

Manor

At Manor, the Trust drilled 14 (14.0 net) wells, including 3 (3.0 net) 75 metre infill horizontal wells, adding over 1,000 boe/d of initial incremental light oil production with high netbacks. The Trust's drilling activities resulted in proved plus probable reserves additions of 459 mboe at year end 2007.

During the year, the Trust expanded its water handling facilities to accommodate increased fluid production and commenced construction to tie in gas from Manor North, which was completed in February of 2008, addition 550 mcf/d of interest sales gas. The Trust will drill up to 10 (7.7 net) wells in 2008, including 3 (3.0 net) 75 metre infill horizontal locations.

Tatagwa

Based on detailed geological and reservoir engineering studies conducted during 2006 at the Tatagwa Unit, the Trust drilled 4 (2.8 net) water injection wells and expanded its water handling facilities to accommodate increased production. Independent engineers have assigned a proved plus probable recovery factor of 11.5 percent to the Unit, representing an incremental 4.7 percent increase from 2003 when the Trust acquired its interest in the Unit. This represents an incremental 7.8 mmboe of proved plus probable reserves.

In 2008, Crescent Point will drill up to 6 (4.2 net) water injection wells and up to 3 (2.1 net) oil wells at Tatagwa to further improve water flood efficiencies and improve recoveries.

Oil and Gas Wells

The following table summarizes our interest as at December 31, 2007 in wells that are producing and non-producing.

Producing Wells					
Area	Oil		Gas		
	Gross	Net	Gross	Net	
SE Saskatchewan	1,522	927.5	12	8.3	
SW Saskatchewan	400	206.0	0	0	
South Central Alberta	358	206.8	240	137.5	
NE B.C./Peace River Arch	50	41.1	79	34.4	
Totals	2,330	1,381.4	331	180.2	

Non-Producing Wells					
Area	Oil		Gas		
	Gross	Net	Gross	Net	
SE Saskatchewan	0	0	0	0	
SW Saskatchewan	0	0	0	0	
South Central Alberta	0	0	0	0	
NE B.C./Peace River Arch	0	0	0	0	
Totals	0	0	0	0	

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which we have an interest and also the number of net acres for which our rights to develop or exploit will, absent further action, expire within one year.

	As of December 31, 2007		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
British Columbia	147,191	80,617	16,340
Alberta	139,092	81,806	8,977
Saskatchewan	287,771	261,685	54,671
Manitoba	317	317	101
New Brunswick	107,994	53,997	0
Total	682,365	478,422	80,089

Drilling Activity

The following table summarizes the gross and net exploration and development wells in which we participated during the year ended December 31, 2007.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	142	101.2	0	0	142	101.2
Natural Gas wells	0	0	0	0	0	0
Service wells	6	4.8	0	0	6	4.8
Standing Wells	1	1.0	0	0	1	1.0
Dry Holes	0	0	0	0	0	0
Total	149	107.0	0	0	149	107.0

For details on the most important current and likely exploration and development activities during 2008, see “*Statement Of Reserves Data And Other Oil And Gas Information – Oil and Gas Properties*”.

Additional Information Concerning Abandonment and Reclamation Costs

We estimate well abandonment costs stereotypically area by area. Such costs are assigned to the reserve wells in the Crescent Point Energy Trust Engineering Report and are included as deductions in arriving at future net revenue. The expected total abandonment costs included in the Trust’s Engineering Report for an estimated 2,075 net wells under the proved reserves category is \$77.063 million undiscounted (\$20.294 million discounted at 10%), of which a total of \$5.043 million is estimated to be incurred in 2008, 2009 and 2010.

Tax Horizon

As a result of our tax efficient structure, annual taxable income is transferred from our operating entities to the Trust, and from the Trust to Unitholders. The current business model is to remain an oil and gas trust. The Trust will continue under the existing tax structure through to the end of 2010, and then going forward, be subject to the tax imposed under the SIFT Rules.

Costs Incurred

The following table summarizes our property acquisition costs, exploration costs and development costs for the year ended December 31, 2007. The total capital costs were approximately \$1.296 billion in 2007.

	Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Total (M\$)	831,725	278,759	0	185,845

Production Estimates

The following table discloses for each product type the gross volume of production estimated by GLJ and Sproule for 2008 in the estimates of future net revenue with forecast pricing from proved reserves disclosed above under the heading “Disclosure of Reserves Data”.

Region	Light and Medium		Natural Gas	NGLs	Total
	Crude Oil	Heavy Crude Oil			
	(bbl/d)	(bbl/d)	(Mcf/d)	(bbl/d)	(boe/d)
SE Saskatchewan	22,112	0	8,398	1,346	24,858
SW Saskatchewan	5,382	61	189	0	5,475
South Central Alberta	1,187	658	13,192	22	4,066
NE B.C./Peace River Arch	954	0	9,097	109	2,579
Total	29,635	719	30,876	1,477	36,977

The following table discloses for each product type the gross volume of production estimated by GLJ and Sproule for 2008 in the estimates of future net revenue with forecast pricing from proved plus probable reserves disclosed above under the heading "Disclosure of Reserves Data".

Region	Light and Medium				Total
	Crude Oil (<i>bbl/d</i>)	Heavy Crude Oil (<i>bbl/d</i>)	Natural Gas (<i>Mcf/d</i>)	NGLs (<i>bbl/d</i>)	
SE Saskatchewan	23,540	0	8,897	1,418	26,441
SW Saskatchewan	5,601	63	196	0	5,697
South Central Alberta	1,331	690	14,081	25	4,393
NE B.C./Peace River Arch	1,076	0	10,303	127	2,920
Total	31,548	753	33,477	1,570	39,450

Production History

The following table discloses, on a quarterly and annual basis for the year ended December 31, 2007, our share of average daily production volume, prior to royalties, and the prices received, royalties, production costs and transportation costs incurred and netbacks on a per unit of volume basis for each product type.

Average Daily Production Volume

	Three Months Ended				Year Ended
	March 31, 2007	June 30, 2007	Sept. 30, 2007	Dec. 31, 2007	Dec. 31, 2007
Light and Medium Crude Oil (<i>bbl/d</i>)	20,786	21,693	22,738	27,285	23,144
Heavy Crude Oil (<i>bbl/d</i>)	969	626	585	523	674
NGLs (<i>bbl/d</i>)	307	500	523	793	531
Natural gas (<i>Mcf/d</i>)	19,377	20,109	22,357	28,500	22,610
Total (<i>boe/d</i>)	25,291	26,170	27,572	33,351	28,117

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Light and Medium Crude Oil

(\$ per bbl)	Three Months Ended				Year Ended
	March 31, 2007	June 30, 2007	Sept. 30, 2007	Dec. 31, 2007	Dec. 31, 2007
Prices Received – net of hedging	60.20	64.70	69.19	71.55	66.86
Royalties	(10.27)	(11.58)	(13.06)	(13.98)	(12.37)
Production Costs	(9.13)	(9.15)	(9.09)	(8.93)	(9.06)
Transportation Costs	(1.72)	(1.63)	(1.85)	(1.97)	(1.81)
Netback	39.08	42.34	45.19	46.67	43.62

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Heavy Crude Oil

(\$ per bbl)	Three Months Ended				Year Ended
	March 31, 2007	June 30, 2007	Sept. 30, 2007	Dec. 31, 2007	Dec. 31, 2007
Prices Received – net of hedging	51.67	49.86	54.67	54.53	51.96
Royalties	(6.72)	(4.97)	(5.33)	(5.85)	(5.84)
Production Costs	(7.65)	(6.96)	(7.36)	(7.27)	(7.18)
Transportation Costs	(1.44)	(1.24)	(1.50)	(1.61)	(1.43)
Netback	35.86	36.69	40.48	39.80	37.51

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – NGLs

(\$ per bbl)	Three Months Ended				Year Ended
	March 31, 2007	June 30, 2007	Sept. 30, 2007	Dec. 31, 2007	Dec. 31, 2007
Prices Received – net of hedging	50.33	48.09	42.98	59.76	51.63
Royalties	(7.12)	(6.05)	(6.18)	(6.86)	(6.55)
Production Costs	(7.62)	(6.80)	(5.65)	(7.46)	(7.00)
Transportation Costs	(1.44)	(1.21)	(1.15)	(1.65)	(1.40)
Netback	34.15	34.03	30.00	43.79	36.68

Prices Received, Royalties, Production Costs and Transportation Costs Incurred and Netback – Natural Gas

(\$ per Mcf)	Three Months Ended				Year Ended Dec. 31, 2007
	March 31, 2007	June 30, 2007	Sept. 30, 2007	Dec. 31, 2007	
Prices Received – net of hedging	7.46	7.17	5.66	6.44	6.62
Royalties	(1.01)	(2.51)	(0.95)	(1.31)	(1.42)
Production Costs	(1.97)	(2.03)	(1.54)	(1.87)	(1.84)
Transportation Costs	(0.26)	(0.26)	(0.20)	(0.18)	(0.22)
Netback	4.22	2.37	2.97	3.08	3.14

Production Volume by Field

The following table discloses for each important field, and in total, our production volumes for the year ended December 31, 2007 for each product type.

Region	Light and Medium		NGLs (bbl/d)	Natural Gas (Mcf/d)	Total (boe/d)	%
	Crude Oil (bbl/d)	Heavy Crude Oil (bbl/d)				
SE Saskatchewan	16,024	35	491	3,791	17,181	61
SW Saskatchewan	4,984	-	-	166	5,012	18
South Central Alberta	1,422	639	26	14,798	4,553	16
NE B.C./Peace River Arch	714	-	14	3,855	1,371	5
Total	23,144	674	531	22,610	28,117	100

ADDITIONAL INFORMATION RESPECTING THE TRUST

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. Each Trust Unit entitles the holder to one vote at any meeting of the holders of Trust Units and represents an equal fractional undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding up of the Trust. All Trust Units rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the Trust Units held by such holder (see “*Redemption Right*”) and to one vote at all meetings of Unitholders for each Trust Unit held.

The Trust Units do not represent a traditional investment and should not be viewed by investors as “shares” in either CPRI or the Trust. As holders of Trust Units in the Trust, Unitholders do 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 price per Trust Unit will be a function of our anticipated distributable income and our ability to effect long term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and our ability to acquire additional assets. Changes in market conditions may adversely affect the trading price of the Trust Units. See “*Risk Factors – Nature of Trust Units and the Trust*”.

The Trust is a limited purpose unincorporated trust established under the laws of the Province of Alberta, which is governed by the terms and conditions of the Trust Indenture. As the Trust is not a corporate entity, it is not governed by the provisions of either provincial or federal corporate law. The Trust Units do not represent a traditional investment and should not be viewed by investors as “shares” in either CPRI or the Trust. As holders of Trust Units, Unitholders do not have the statutory rights normally associated with ownership of shares of a corporation. As a result, in the event a restructuring of the Trust were necessary, the Trust would not be able to access the remedies available thereunder. In the event of a restructuring, a Unitholder may be in a different position than a shareholder of a corporation. See “*Risk Factors – Nature of Trust Units and the Trust*”.

Trust Units are not “deposits” within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the 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.

As of March 15, 2008, there were 121,669,469 Trust Units outstanding and 3,834,542 Trust Units reserved for issuance pursuant to the Restricted Unit Bonus Plan. Of the 3,834,542 Trust Units reserved for issuance as of March 15, 2008, Restricted Units in respect of 1,570,717 Trust Units have been granted and remain outstanding.

Income Stream

We make monthly cash distributions to Unitholders from our net cash flow. Our primary sources of cash flow are distributions from the Limited Partnership and the CPC Trust and interest income from CPC Trust.

The Participating Note

The Participating Note was created and issued by CPC Trust to the Trust on January 6, 2004. The Participating Note is a grid, unsecured note and bears interest between 0 and 14% per annum. Advances are made under the Participating Note from time to time, largely to finance acquisitions. Interest under the Participating Note is payable monthly in arrears. As at March 15, 2008, the aggregate principal amount owing under the Participating Note was approximately \$380.8 million.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust or its obligations or affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges or losses suffered by a Unitholder from or arising as a result of such Unitholder not having such limited liability.

The Trust Indenture provides that all contracts signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to Unitholders of this nature arising is considered unlikely in view of the fact that the sole activity of the Trust is to hold securities and all of our business operations are carried on by CPRI, the Limited Partnership and CPC Trust, directly or indirectly.

The activities of the Trust and its direct and indirect wholly-owned subsidiaries, CPRI, CPGPC and CPC 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 to the Unitholders for claims against the Trust including by obtaining appropriate insurance, where available, for the operations of CPRI and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon Unitholders personally.

On July 1, 2004, the Province of Alberta proclaimed the *Income Trusts Liability Act* (Alberta) in force. This legislation provides that beneficiaries of Alberta based income trusts are not liable, as beneficiaries, for any act, default, obligation or liability of the income trust. Unitholders of the Trust have the benefit of this legislation with respect to liabilities arising on or after July 1, 2004.

Issuance Of Trust Units

The Trust Indenture provides that Trust Units, including rights, warrants (including so called "special warrants" which may be exercisable for no additional consideration) and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee may determine, including, without limitation, instalment or subscription receipts. The Trust Indenture also provides that the Trustee may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust which debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as the Trustee may determine.

Cash Distributions

The Trustee may declare payable to the Unitholders all or any part of the net income of the Trust earned from income generated under its investment in partnership and debt instruments, less all expenses and liabilities of the Trust due and accrued and which are chargeable to the net income of the Trust. It is anticipated, however, that the Trust will reinvest a substantial portion of any such repayments of principal in respect of the debt to make capital expenditures to develop its business with a view to enhancing cash flow from operations. See "*Distributions*".

Generally, cash distributions will be made on the 15th day of each month to Unitholders of record on the immediately preceding distribution record date.

Redemption Right

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to our transfer agent of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice

to redeem Trust Units by the transfer agent, the holder thereof shall only be entitled to receive a price per Trust Unit (the “Market Redemption Price”) equal to the lesser of: (i) 90% of the “market price” of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the first trading day following the date on which the Trust Units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

For the purposes of this calculation, “market price” is an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that, if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The “closing market price” shall be an amount equal to the closing price of the Trust Units if there was a trade of the Trust Units on the date and the exchange or other market provides a closing price thereof; an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; or the average of the last bid and last ask prices if there was no trading on the date.

The aggregate Market Redemption Price payable by the Trust in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cheque, drawn on a Canadian chartered bank or trust company in lawful money of Canada, on the last day of the month following the month in which the Trust Units were tendered for redemption. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month shall not exceed \$250,000; provided that, the Trust may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month by the Trust distributing notes (herein referred to as “Redemption Notes”) having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption. In the event of distribution of Redemption Notes, each Redemption Note so distributed to the redeeming holder of Trust Units shall be in the principal amount of \$100.

If at the time Trust Units are tendered for redemption by a Unitholder, (i) the outstanding Trust Units are not listed for trading on the TSX and are not traded or quoted on any other stock exchange or market which CPRI considers, in its sole discretion, provides representative fair market value price for the Trust Units or (ii) trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption then such Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the “Appraised Redemption Price”) equal to 90% of the fair market value thereof as determined by CPRI as at the date on which such Trust Units were tendered for redemption. The Appraised Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Notes or Redemption Notes which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Notes or Redemption Notes. Notes or Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Non-Resident Unitholders

It is in the best interest of Unitholders that the Trust qualify as a “unit trust” and a “mutual fund trust” under the Tax Act. Certain provisions of the Tax Act require that the Trust not be established nor maintained primarily for the benefit of non-residents (as defined below). Accordingly, in order to comply with such provisions, the Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are non-residents. In this regard, the Trust shall, among other things, take all necessary steps to monitor the ownership of the Trust Units to carry out such intentions. For example, the Trust monitors the ownership of Trust Units by having its transfer agent provide a report on non-resident ownership on a regular basis. If at any time the Trust becomes aware that the beneficial owners of 40% or more of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trust shall take such action as may be necessary to carry out the intentions evidenced herein. For the purposes of this Section, “non-residents” means non-residents of Canada within the meaning of the Tax Act.

Meetings of Trust Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture (except as described under “*Amendments to the Trust Indenture*”), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding up the affairs of the Trust. Meetings of Unitholders will be called and held annually for, among other things, the election of the directors of CPRI and the appointment of the auditors of the Trust.

A meeting of Unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned in writing by (i) CPRI or (ii) the holders of Trust Units holding in aggregate not less than 5% of the votes entitled to be voted at a meeting of Unitholders. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxy holder need not be a Unitholder. Two persons present in person, or represented by proxy, and representing in the aggregate at least 5% of the votes attaching to all outstanding Trust Units shall constitute a quorum for the transaction of business at all such meetings.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders in accordance with the requirements of applicable laws.

Exercise of Voting Rights

The Trust Indenture prohibits the Trustee from voting the shares of CPRI with respect to (i) the election of directors of CPRI or (ii) the removal of a director of CPRI or the election of a director to fill such vacancy, except in accordance with an ordinary resolution adopted at an annual meeting of Unitholders. The Trustee is also prohibited from voting the shares of CPRI, units of CPC Trust or the Limited Partnership to authorize:

- (a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of the Trust, except in conjunction with an internal reorganization of the direct or indirect assets of CPRI as a result of which either CPRI or the Trust has an economically equivalent interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization or a pledge, mortgage, charge or security interest;
- (b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving CPRI, CPGPC, CPC Trust or the Limited Partnership and any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above, the winding up, liquidation or dissolution of CPRI, CPC Trust, CPGPC or the Limited Partnership prior to the end of the term of the Trust except in conjunction with an internal reorganization as referred to in paragraph (a) above; and
- (c) a termination of the Administration Agreement;

without the approval of the Unitholders by special resolution at a meeting of Unitholders called for that purpose.

The Trustee shall not, without the approval of the board of directors of CPRI, vote the Trust’s interests in CPRI, CPC Trust or the Limited Partnership, to authorize:

- (a) any sale, transfer or other disposition of securities issued by CPGPC, CPC Trust, Limited Partnership or CPRI,
- (b) any issuance of securities of the Trust,
- (c) any acquisition or investment in securities of any entity, including without limitation, bodies corporate, partnerships or trusts,
- (d) any borrowing of funds, incurring any other form of indebtedness or otherwise obtaining credit in the name of the Trust, or
- (e) any disposition of any part of the property of the Trust;

The Trustee is also prohibited from voting the shares of CPRI, the units of CPC Trust or the shares of CPGPC to authorize:

- (a) the winding up, liquidation or dissolution of CPRI, CPC Trust, CPGPC or the Limited Partnership prior to the end of the term of the Trust except in conjunction with an internal reorganization as referred to in paragraph (a) above;
- (b) any amendment to the articles of CPRI to increase or decrease the minimum or maximum number of directors;

- (c) any material amendment to the articles of CPRI or CPGPC to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of CPRI's shares or CPGPC's shares in a manner which may be prejudicial to the Trust; and
- (d) any material amendment to the LP Agreement, the Mission LP Agreement or the CPC Trust Indenture which may be prejudicial to the Trust.

Trustee

Olympia Trust Company is the initial Trustee of the Trust. The Trustee is responsible for, among other things, accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto, maintaining the books and records of the Trust and providing timely reports to holders of Trust Units. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The initial term of the Trustee's appointment is until the third annual meeting of Unitholders. The Unitholders shall, at the third annual meeting of Unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, the Unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders three years following the reappointment or appointment of the successor to the Trust. The Trustee may also be removed by special resolution of the Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Delegation of Authority, Administration and Trust Governance

The board of directors of CPRI has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to CPRI responsibility for any and all matters relating to the following: (i) an offering of securities of the Trust; (ii) ensuring compliance with all applicable laws, including in relation to an offering of securities of the Trust; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any investments of the Trust or any subsequent investments; and (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents shall not be liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the property of the Trust, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, prima facie, properly executed, any depreciation of, or loss to, the property of the Trust incurred by reason of the sale of any asset, any inaccuracy in any evaluation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of CPRI, or any other person to whom the Trustee has, with the consent of CPRI, delegated any of its duties hereunder, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by CPRI to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the property of the Trust. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to the Trust Indenture

The Trust Indenture may be amended or altered from time to time by special resolution of the Unitholders. In addition, the Trustee may, without the approval of any of the Unitholders, amend the Trust Indenture for the purpose of:

- (a) ensuring the Trust's continuing compliance with applicable laws, regulations, policies or requirements of any governmental agency or authority of Canada or of any province;

- (b) ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) of the Tax Act as from time to time amended or replaced;
- (c) ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;
- (d) removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture and any other agreement of the Trust or any offering document pursuant to which securities of the Trust are issued with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the Unitholders are not prejudiced thereby;
- (e) providing for the electronic delivery by the Trust to the Unitholders of documents relating to the Trust (including annual and quarterly reports, financial statements, notices of Unitholder meetings and information circulars and proxy related materials) once applicable securities laws have been amended to permit such electronic delivery in place of normal delivery procedures, provided that such amendments to the Trust Indenture are not contrary to or do not conflict with such laws;
- (f) the Trustee shall vote the securities of CPRI with regard to the appointment of auditors of CPRI so as to ensure that such auditors are the same as the auditors appointed by Unitholders;
- (g) the Trustee shall not, without the approval of the Unitholders by Special Resolution adopted at a meeting of Unitholders called for that purpose and provision of the notice required pursuant to the terms thereof, terminate the Administration Agreement;
- (h) making any modifications in the form of Trust Unit Certificates to conform with the provisions of the Trust Indenture, or any other modifications, provided the rights of the Trustee and of the Unitholders are not prejudiced thereby;
- (i) curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of the Unitholders are not prejudiced thereby; and
- (j) changing the status of or the laws governing the Trust which, in the opinion of the Trustee, is desirable in order to provide Unitholders with the benefit of any legislation limiting their liability.

Takeover Bid

The Trust Indenture contains provisions to the effect that, if a takeover bid is made for the Trust Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the takeover bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the take-over bid on the terms offered by the offeror. In the event of a take-over bid for Trust Units, any holder of a security exchangeable directly indirectly into Trust Units may, unless prohibited by the terms and conditions of such exchangeable security, convert, exercise or exchange such exchangeable security for the purpose of tendering Trust Units to the take-over bid, unless an identical offer is made by the offeror to purchase such exchangeable security.

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of Unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the outstanding Trust Units and Special Voting Rights; (b) a quorum of 50% of the issued and outstanding Trust Units and Special Voting Rights is present in person or by proxy; and (c) the termination must be approved by special resolution of Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trust shall continue in full force and effect for a period which shall end twenty-one years after the date of death of the last surviving issue of Her Majesty, Queen Elizabeth II. In the event that the Trust is wound up, the Trustee will sell and convert into money the property of the Trust in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the property of the Trust, and shall in all respects act in accordance with the directions, if any, of the Unitholders in respect of termination authorized pursuant to the special resolution authorizing the termination of the Trust. After paying, retiring or discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Trust and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the Unitholders in accordance with their pro rata share.

Reporting to Trust Unitholders

Our financial statements will be audited annually by a recognized firm of independent chartered accountants. Our audited financial statements, together with the report of such chartered accountants, will be mailed by the Trustee to Unitholders and our unaudited interim financial statements will be mailed to Unitholders as required by and within the periods prescribed by securities legislation. Our year end is December 31.

The Trust is subject to continuous disclosure obligations under all applicable securities legislation.

Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan

On November 24, 2003, we adopted a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP Plan"). Under the DRIP Plan, eligible Unitholders may, at their option, reinvest their cash distributions to purchase additional Trust Units at 95% of the average market price (as defined in the DRIP Plan) of a Trust Unit on the applicable distribution date. The DRIP Plan also provides an alternative where eligible Unitholders may elect, under the premium distribution component, to receive a premium cash distribution equal to 102% of the reinvested cash distribution that such Unitholders would have otherwise been entitled to receive on the applicable distribution date.

The DRIP Plan also permits those Unitholders who participate in either the regular distribution reinvestment component or the premium distribution component of the DRIP Plan to purchase additional Trust Units from treasury at the average market price (as defined in the DRIP Plan) in minimum amounts of \$1,000 per remittance and maximum aggregate amounts of \$10,000 per month, all subject to an overall annual DRIP Plan limit of 2% of the outstanding Trust Units. Generally, no commissions, service charges or brokerage fees will be payable by Unitholders who participate in the DRIP Plan. We have reserved the right to determine how much new equity is available under the Plan on any particular distribution date. Accordingly, participation in the DRIP Plan may be pro-rated in certain circumstances.

Registered and beneficial owners of units who are not resident in Canada are not eligible to participate in the DRIP Plan.

From October 31, 2006 to December 2007, we used the proceeds from the issuance of Trust Units under the DRIP Plan to reduce our then outstanding debt. The operation of the DRIP Plan was suspended in December 2007 and remains suspended.

Credit Facilities

The Trust has credit facilities (the "Credit Facilities") which provide for a \$740 million extendible revolving loan facility (the "Credit Facility") and a \$60 million operating loan facility (the "Bi-Lateral Credit Facility"). The loan's interest rate is based on either Canadian prime rate, versus base rate or bankers acceptance rates at the Trust's option subject to certain basis point or stamping fee adjustments ranging from 0% to 1.5% depending on the Trust's debt to cash flow ratio. The Credit Facilities are secured by \$1.5 billion floating charge demand debenture, a general security agreement and a subordination agreement from the Trust covering all assets and cash flows. The Credit Facilities are subject to review on an annual basis, with the next review anticipated to take place in May 2008. Various borrowing options are available under the Credit Facilities, including Canadian prime rate-based advances, U.S. base rate-based advances and advances by way of bankers' acceptances. The Credit Facilities constitute a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period, subject to a one year term maturity as to lenders not agreeing to such annual extension. The Credit Facilities contain standard commercial covenants for facilities of this nature, and distributions by CPRI to the Trust (and effectively by the Trust to Unitholders) are subordinated to the repayment of any amounts owing under the Credit Facilities. Distributions to Unitholders are not permitted if the Trust is in default of such Credit Facilities or if the amount of the Trust's outstanding indebtedness under such facilities exceeds the then existing current borrowing base. The borrowing base under the Credit Facilities is \$800 million.

ADDITIONAL INFORMATION RESPECTING CPRI

CPRI has generally been delegated responsibility relating to significant management and operational decisions involving the Trust and the crude oil and natural gas properties underlying the Trust. See "*Additional Information Respecting the Trust – Delegation of Authority, Administration and Trust Governance*".

Directors and Officers

CPRI has a board of directors currently consisting of seven individuals. The directors are elected by the Trust, at the direction of Unitholders by ordinary resolution, and hold office until the next annual meeting of the Trust, which will be held on May 31, 2008.

The name, municipality of residence and principal occupation during the last five years of each of the directors and executive officers of CPRI are as follows:

Name and Municipality of Residence	Position Held with the Corporation	Date First Elected or Appointed as Director
Scott Saxberg ⁽⁴⁾ Calgary, Alberta	President, Chief Executive Officer and Director	2003
Greg Tisdale Calgary, Alberta	Chief Financial Officer	Not applicable
C. Neil Smith Calgary, Alberta	Vice President, Engineering and Business Development	Not applicable
Dave Balutis Calgary, Alberta	Vice President, Geosciences	Not applicable
Tamara MacDonald Calgary, Alberta	Vice President, Land	Not applicable
Ken Lamont Calgary, Alberta	Controller and Treasurer	Not applicable
Mark Eade Calgary, Alberta	Corporate Secretary	Not applicable
Peter Bannister ^{(1), (3)} Calgary, Alberta	Director and Chairman	2003
Paul Colborne ^{(2), (4)} Calgary, Alberta	Director	2003
D. Hugh Gillard ^{(1), (2), (3)} Calgary, Alberta	Director	2003
Greg Turnbull ^{(2), (5)} Calgary, Alberta	Director	2003
Kenney F. Cugnet ^{(3), (4), (5)} Weyburn, Saskatchewan	Director	2003
Gerald A. Romanzin ^{(1), (5)} Calgary, Alberta	Director	2004

Notes:

- (1) Member of the audit committee.
- (2) Member of the compensation committee.
- (3) Member of the reserves committee.
- (4) Member of the environment, health and safety committee.
- (5) Member of corporate governance and nominating committee.

As at March 15, 2008, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 2,300,070 Trust Units, representing approximately 1.89% of the issued and outstanding Trust Units.

Scott Saxberg, President, Chief Executive Officer and Director

Mr. Saxberg is currently the President, Chief Executive Officer and a director of CPRI. From the date of the Arrangement, Mr. Saxberg served as the President, Chief Operating Officer and Director of CPRL, the former administrator of the Trust. Prior to the completion of the Arrangement, he was the Vice President, Operations of Crescent Point and was one of the founding shareholders of Crescent Point.

Prior to joining Crescent Point, Mr. Saxberg worked in various roles from 1991 to 1996 with Wascana Energy and Numac Energy, both western crude oil and natural gas exploration and production companies whose shares traded on the TSX. In August 1996, Mr. Saxberg joined Magin Energy Inc. as a senior engineer responsible for a multitude of engineering related duties, including drilling, completions, field staff, production operations, facilities design, reservoir engineering, reserves, budgeting, and acquisitions and divestitures. Mr. Saxberg became Western Area Manager in June 1997, responsible for Magin's production west of the fifth and sixth meridians. In August 1999, Mr. Saxberg was promoted to Manager of Business Development, responsible for the identification and evaluation of corporate and land acquisitions. In June 2001, Magin was acquired by NCE Petrofund, Inc.

Mr. Saxberg holds a Bachelor of Science in Mechanical Engineering from the University of Manitoba. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and has over seventeen years of experience in the oil and gas industry. Mr. Saxberg is also the Chief Executive Officer of Shelter Bay Energy Inc. and serves on the Board of Directors of Bellamont Exploration Ltd. and Wild River Resources and on the Board of Directors of each of the general partners of Catapult Energy Small Cap 2007 FTS Limited Partnership and Catapult Energy Small Cap FTS Limited Partnership. Mr. Saxberg also serves on the CAPP Board of Governors.

Greg Tisdale, Chief Financial Officer

Greg Tisdale is currently the Chief Financial Officer of CPRI. Mr. Tisdale was the Chief Financial Officer of CPRL, the former administrator of the Trust and prior to that Mr. Tisdale served as Vice President, Finance of Direct Energy Marketing Ltd. ("Direct Energy"), a multinational retail energy provider, since September 2003. In this role, Mr. Tisdale provided financial oversight of the gas and power trading activities in North America and the company's upstream oil and gas production in the Western Canadian Sedimentary Basin, and formed part of the management team responsible for any upstream asset acquisitions.

Prior to joining Direct Energy, Mr. Tisdale held senior management positions with AltaGas Services Inc. ("AltaGas") from 2002 to 2003, Shell Trading Gas & Power Canada Ltd. ("Shell Trading") from 1998 to 2002, and Engage Energy Inc. ("Engage Energy") from 1994 to 1998.

In his position at AltaGas, Mr. Tisdale was responsible for the development of a corporate strategy around executing a power generation business line. This involved integrating the acquisition of a 353 megawatt ("MW") power plant along with an additional 100 MW structured product. In his roles at Shell Trading and Engage Energy, Mr. Tisdale managed financial aspects surrounding all gas and power trading activities for the Canadian operations and was a member of the leadership teams that contributed to North American and global finance initiatives.

Mr. Tisdale holds a Bachelor of Commerce degree from University of Alberta (with distinction), is a Chartered Accountant, is a member of the Institute of Chartered Accountants of Alberta and is a member of the Financial Executive Institute. Mr. Tisdale also serves on the Board of Directors of Shelter Bay Energy Inc. and Enseco Energy Services Corp.

C. Neil Smith, Vice President, Engineering and Business Development

Mr. Smith is the Vice President, Engineering and Business Development of CPRI. His duties include responsibility for all aspects of CPRI's capital, operations and business development evaluation activities, as well as participating, with the executive team, in sourcing new value added growth opportunities. He is part of the team that has grown the Trust from 7,000 boe/d at inception to over 35,000 boe/d and acquired over \$2.0 billion of high quality, long life assets. Prior to joining CPRL in August 2003, Mr. Smith spent six years as the Manager, Business Development at PrimeWest Energy Inc. He was directly responsible for overseeing the evaluation and due diligence in respect of over \$1 billion of corporate and property acquisitions, as well being the lead negotiator on over \$100 million of asset transactions. He was part of the team that developed and executed successful acquisition strategies that grew PrimeWest Energy Trust from 10,000 boe/d to over 34,000 boe/d. Mr. Smith has over twenty years of industry business and technical experience, including four years with Coles Gilbert Associates Ltd., the predecessor to GLJ Petroleum Consultants and Amoco Canada Resources Ltd. He is a registered professional engineer in the Province of Alberta and a member of the Canadian Institute of Mining's Petroleum Division.

Mr. Smith holds a Bachelor of Applied Science in Geological Engineering from the University of British Columbia and Masters in Business Administration majoring in Finance (Dean's list) from the University of Calgary. At December 31, 2007, Neil Smith was on the Board of Directors of Spear Exploration Inc., a private oil and gas company which subsequently was sold in February 2008. Mr. Smith is also the President of Shelter Bay Energy Inc. and is a director of the Petroleum and Acquisition Association (PADA).

Dave Balutis, Vice President, Geosciences

Mr. Balutis is currently Vice President, Geosciences of CPRI, prior to which he had the same role for CPRL, the former administrator of the Trust. Previously, he was one of the founding shareholders and a senior development geologist of Crescent Point from July 2001 to the completion of the Arrangement. From September 1997 to June 2001, Mr. Balutis was employed as senior exploration and development geologist by Magin. From 1991 to 1997, Mr. Balutis was employed by Numac Energy Ltd., and its predecessor, in various levels of increasing responsibility including Team Leader, Project Manager and Manager of Development. His duties included implementation of exploration, development and acquisition strategies throughout southeast Saskatchewan and Alberta. Mr. Balutis commenced his career at Dome Petroleum in 1981 as an exploration and development geologist working throughout Alberta.

Mr. Balutis graduated in 1981 from the University of Alberta with a Bachelor of Science in Geology (Hons.). Mr. Balutis is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and has over 25 years of experience in the oil and gas industry.

Tamara MacDonald, Vice President, Land

Ms. MacDonald is currently the Vice President, Land of CPRI, prior to which she held the same position with CPRL, the former administrator of the Trust. Prior to joining CPRL in September 2004, Ms. MacDonald was Senior Landman at Petrofund Energy Trust ("Petrofund"), a Calgary based energy trust. From December 1997 to August 2004, Ms. MacDonald actively participated in Petrofund's growth from 4,000 boe/d to 37,000 boe/d. While at Petrofund, Ms. MacDonald was also exposed to over 30 separate drilling limited partnerships under the governing entity NCE Resources Group Inc., and was responsible for the negotiation and management of lands within each of such limited partnerships.

From July 1997 to November 1997, Ms. MacDonald was responsible for Alberta negotiations at Merit Oil & Gas, and from January 1997 to June 1997, she was responsible for the southern Alberta negotiations at Tarragon Oil & Gas. From May 1992 to December 1996, Ms. MacDonald was employed by Northstar Energy Corporation as Landman with various responsibilities, including functions related to acquisitions and divestments.

Ms. MacDonald graduated in 1992 from the University of Calgary with a Bachelor of Commerce, majoring in Petroleum Land Management. Ms. MacDonald is a member of the Canadian Association of Petroleum Landmen and has over 16 years of experience in exploration and land acquisitions in the oil and gas industry. Ms. MacDonald is also the Vice President of Land of Shelter Bay Energy Inc.

Ken Lamont, Controller and Treasurer

Mr. Lamont is currently Controller and Treasurer of CPRI, prior which he held the same position with CPRL, the former administrator of the Trust. Prior to joining Crescent Point in May 2005, Ken Lamont was the Director of Finance, Energy Management Group of Direct Energy. There, he was responsible for the financial supervision of gas and power trading activities for Direct Energy's Canadian operations and for upstream oil and gas production in the Western Canadian Sedimentary Basin. Previously, Mr. Lamont held senior management positions with Shell Trading Gas & Power Canada Ltd. where he was responsible for all aspects of finance pertaining to Canadian operations and with PricewaterhouseCoopers LLP as a senior manager in the audit and business advisory practice.

Mr. Lamont graduated with distinction from the University of Alberta with a Bachelor of Commerce. He is a Chartered Accountant and member of the Institute of Chartered Accountants of Alberta. Mr. Lamont is also the Chief Financial Officer of Shelter Bay Energy Inc.

Mark Eade, Corporate Secretary

Mr. Eade has been a partner with the law firm McCarthy Tétrault LLP since 2001 practicing in the area of corporate and securities law.

Mr. Eade received his Bachelor of Commerce Degree (Hons.) from the University of Saskatchewan in 1989 and his Bachelor of Laws Degree from the University of Saskatchewan in 1993. He was called to the Alberta bar in 1994. Mr. Eade is a member of the Law Society of Alberta and the Canadian Bar Association.

Paul Colborne, Director

Paul Colborne is currently the President of Star Valley Oil and Gas Ltd., a private, Calgary-based oil and gas company. Mr. Colborne is also Chairman of Tristar Oil and Gas Ltd., a 20,000 boe/d publicly traded oil and gas company. He also serves on the Board of Directors of Crescent Point Energy Trust, Breaker Energy Ltd., Twin Butte Energy Ltd., Sikanni Services Ltd. and Seaview Energy Inc. From September 2003 to January 2005, Mr. Colborne was the President and CEO of StarPoint Energy Ltd. until its reorganization into StarPoint Energy Trust, a 36,000 boe/d publicly traded energy trust. Prior thereto, Mr. Colborne was the President and CEO of Crescent Point Energy Ltd. until its reorganization into Crescent Point Energy Trust in September 2003. From 1993 to 2001, Mr. Colborne was the President and CEO of Startech Energy Ltd., an intermediate oil and gas exploration and production company. Under Mr. Colborne's leadership, Startech grew to 16,000 boe/d

from its start-up production rate of 120 boe/d. Listed on the TSX 300 sub-index as one of Canada's larger public oil and gas companies, Startech was acquired by ARC Energy Trust in February 2001. Mr. Colborne's previous career included positions as a corporate finance and oil and gas lawyer with Wascana Energy Inc. and Husky Oil Ltd., and an associate with the legal firm Parlee McLaws. Mr. Colborne has 22 years of industry experience, and has specialized in creating shareholder value in the junior oil and gas sector in Western Canada.

Kenney F. Cugnet, Director

Since 1963, Mr. Cugnet has been the owner and operator of a farm in Weyburn, Saskatchewan, where he currently lives. He has been the President of Valleyview Petroleum Ltd., a private oil and gas company since 1979. He served as the Manager of Field Operations of Tappit and was a director of Tappit from 1987 to 2003 and Chairman of the Board of Tappit from 2000 to 2003 until the company's merge with the Trust in September 2003. Mr. Cugnet joined the Starpoint Energy Inc. board as a director until January 2005. He was a director of Mission Oil & Gas Inc. from January 2005 to February 2007. He has served on the Crescent Point board since its inception in September 2003. Mr. Cugnet is a director of Medora Resources Inc. which is a private company. Mr. Cugnet has also served as a member of the Saskatchewan Surface Rights Arbitration Board from June 1987 to April 1992 and a director of Cypress Petroleum Corp. from November 1991 to May 1995.

D. Hugh Gillard, Director

Mr. Gillard has over thirty years of business experience in the oil and gas industry and is the Principal of Saddleback Resources Ltd., a private company involved in equity investments and advisory roles in the energy sector. From June 2003 to March 2006, he was President, Chief Executive Officer and a director of Kelso Energy Inc., a publicly traded junior oil and gas company. Kelso Energy Inc. subsequently merged with COSTA Energy Ltd. where he continued to serve as a director until December 2006. From 1999 to 2000 he was President, Chief Operating Officer and a director of PrimeWest Energy Trust. From 1990 to 1998, he was employed by CanWest Gas Marketing Inc., a private producer owned gas marketing company. During this period Mr. Gillard initially served as Vice President, Gas Supply and then later as President and Chief Executive Officer. From 1972 to 1989, he held several senior positions with Ashland Oil Canada, Dome Petroleum and Amoco Canada.

Mr. Gillard currently serves as a director of Creststreet Power Income Fund and as a director (Chairman) of Petrowest Energy Services Trust, both publicly traded entities. He also served as a director of Point North Energy Ltd. from October 2005 to November 2006. In September 2006, Point North Energy Ltd., filed for creditor protection due to circumstances arising from events which occurred prior to Mr. Gillard being appointed to the board. In September 2007, a successful plan of arrangement was approved and Point North Energy Ltd. emerged from Companies Creditors Act protection.

Mr. Gillard is a graduate of the University of Calgary (Commerce) and the Stanford Business School Executive Program. He is a past member of the Management Advisory Council (University of Calgary) and past Chairman of the Hospice Calgary Board of Directors.

Peter Bannister, Director and Chairman

Peter Bannister is the President of Destiny Energy Inc., a privately-owned oil and gas company. Until its sale in February 2007, Mr. Bannister was Vice President Exploration and Director of Mission Oil and Gas Inc. Prior to joining Mission Oil and Gas Inc., he was Vice President Exploration of StarPoint Energy Inc. before its conversion to a royalty trust and President and a director of Impact Energy Inc. Mr. Bannister previously held the position of Vice President Corporate Development of Startech Energy until it was acquired by ARC Resources at the end of 2000 and also held positions as Vice President Exploration and Development and Director of both Boomerang Resources Ltd. and Laurasia Resources Limited, both publicly traded oil and gas companies. Mr. Bannister's experience prior to his involvement in public oil and gas companies was as a partner of Sproule Associates Limited, a worldwide petroleum consulting firm specializing in the evaluation of oil and gas properties where he spent 12 years specializing in oil and gas property evaluations and managing private equity investments in the oil and gas business in Western Canada. Mr. Bannister is also a director of Shelter Bay Energy Inc. and Breaker Energy Ltd.

A graduate of the University of Calgary in 1981 he holds a Bachelor of Science degree majoring in Geology with a minor in Economics. Mr. Bannister is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and has 27 years of oil and gas industry experience.

Gregory G. Turnbull, Director

Mr. Turnbull has been a partner with the law firm of McCarthy Tétrault LLP since July 2002 and currently serves as the Regional Managing Partner of the Calgary office. Mr. Turnbull started his career with the law firm of MacKimmie Matthews in 1979. From 1987 to 2001, he was a partner with Gowlings LLP (formerly Code Hunter LLP). In 2001 and 2002, he was a partner with the law firm of Donahue LLP.

Mr. Turnbull is currently a director of Storm Exploration Inc., Heritage Oil Corporation, Seaview Energy Inc., Sunshine Oilsands Ltd., BNP Resources Inc., Action Energy Inc. and Flagship Energy Inc., all publicly traded entities listed on the TSX or TSX Venture Exchange.

Throughout his career, he has served as an officer or director of Baytex Energy Ltd., Barrington Petroleum Ltd., Castle Rock Petroleum Ltd., Hawk Oil Inc., Hawk Energy Inc., Kensington Energy Ltd., Lexxor Energy Inc., Newquest Energy Inc., Mannville Oil & Gas Ltd., Petrostar Petroleum Inc., Pinnacle Resources Ltd., Quadron Resources Ltd., Quintex Energy Ltd., Rally Energy Ltd., ResoQuest Resources Ltd., Seventh Energy Ltd., Tri-Ex Oil & Gas Ltd., Trigas Exploration Ltd., Trimax Energy Inc., Twin Energy Ltd. and Westward Energy Inc.

Mr. Turnbull received his Bachelor of Arts (Honours) Degree from Queen's University in 1976 and his Bachelor of Laws Degree from the University of Toronto in 1979. He was called to the Alberta bar in 1980. Mr. Turnbull is a member of the Law Society of Alberta, the Canadian Bar Association and the Calgary Bar Association.

Gerald A. Romanzin

Gerald Romanzin is an independent Calgary businessman who serves as a director of FET Resources Ltd., Petrowest Energy Services Ltd., Ketch Resources Ltd., Trimac Transportation Services Inc. and Kereco Energy Ltd. He also serves as a trustee of Trimac Income Fund. Mr. Romanzin was the Executive Vice President of the TSX Venture Exchange from November 1999 to April 2002 where he was responsible for overseeing the Corporate Finance group and regional operations. In addition, he assumed the role of Acting President of the TSX Venture Exchange from December 2001 to April 2002. Mr. Romanzin is a chartered accountant and was a financial analyst with the Alberta Securities Commission for four years prior to joining the Alberta Stock Exchange in 1987. Mr. Romanzin was the Executive Vice President of the Alberta Stock Exchange from June 1995 to its change to the TSX Venture Exchange in November 1999.

Mr. Romanzin obtained a Bachelor of Commerce degree from the University of Calgary and is a member of the Institute of Chartered Accountants of Alberta.

Share Capital

CPRI is authorized to issue an unlimited number of common shares and an unlimited number of First Preferred Shares. The Trust is the sole holder of the issued and outstanding common shares of CPRI.

Common Shares

Each common share ("Common Share") entitles its holder to receive notice of and to attend all meetings of the shareholders of CPRI and to one vote at such meetings. The holders of Common Shares are, at the discretion of the board of directors of CPRI and subject to applicable legal restrictions, entitled to receive any dividends declared by the board of directors on the Common Shares. The holders of Common Shares are entitled to share equally in any distribution of the assets of CPRI upon the liquidation, dissolution, bankruptcy or winding up of CPRI or other distribution of its assets among its shareholders for the purpose of winding up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to any other shares having priority over the Common Shares.

First Preferred Shares

The First Preferred Shares are issuable in one or more series. The holders of First Preferred Shares are entitled to priority over the Common Shares with respect to the payment of dividends and the distribution of assets of CPRI in the event of any liquidation, dissolution or winding-up of CPRI. The First Preferred Shares shall rank equally with every other series of First Preferred Shares with respect to the payment of dividends and in the distribution of assets of CPRI in the event of any liquidation, dissolution or winding-up of CPRI or other distribution of assets of CPRI.

Administration Agreement

CPRI has generally been delegated the significant management decisions of the Trust. In particular, pursuant to the Administration Agreement, CPRI has been delegated the responsibility for any and all matters relating to the following: (i) an offering of securities of the Trust; (ii) ensuring compliance with all applicable laws, including in relation to an offering of securities of the Trust; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any of the Trust's investments or any subsequent investments; and (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies

and trusts of similar size. All current legislation is a matter of public record, and we are unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing – Natural Gas

In Canada, the price of natural gas sold intra-provincially or to the United States is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the National Energy Board (“NEB”) and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years requires a general short term export license while terms greater than two years require a specific license for the particular gas sold (in quantities of not more than 30,000 m³/d). 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 NEB 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 – Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers. Oil prices are primarily based on worldwide supply and demand. The specific price paid depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement (“NAFTA”) among the governments of Canada, the U.S. and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. 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; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

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

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations, which govern land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. 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 mineral owner and the lessee. Crown royalties 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, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty-rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. These programs reduce the amount of Crown royalties otherwise payable.

Environmental Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to evolving international conventions and national, provincial, and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition

of fines and penalties, some of which may be material. Certain environmental protection legislation may subject Crescent Point to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas, or other pollutants into the air, soil or water may give rise to liabilities to third parties and may require Crescent Point to incur costs to remedy such discharge in the event that they are not covered by Crescent Point's insurance, which insurance is in line with industry practice. Furthermore, Crescent Point expects incremental future costs associated with compliance with increasingly complex environmental protection requirements, some of which may require the installation of emissions monitoring and measuring devices, and the verification and reporting of emissions data.

As at December 31, 2007, Crescent Point owned approximately 5,613 gross (3,054.1 net) wells for which abandonment and reclamation costs are expected to be incurred. During the 2007 financial year, Crescent Point spent approximately \$1.9 million on well abandonments and environmental remediation activities. Crescent Point estimates that it will spend approximately \$3.8 million on well abandonments and environmental remediation and reclamation activities in 2008, and has budgeted accordingly.

Environmental Regulation

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

Crescent Point's facilities and other operations emit Greenhouse Gases, making it possible that Crescent Point will be subject to Federal and Provincial legislation. 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 GHGs. In April 2007, the Federal Government proposed a new climate change plan that calls for GHG emissions to be reduced by 20 percent below current levels by 2020. This bill has not been passed yet. Facilities have a number of strategies to achieve these targets, including emission tradings, in-house reductions, or invest in a technology fund to research and develop GHG reduction technologies.

In Alberta, new climate change regulations became effective July 1, 2007. These regulations require Alberta facilities that emit more than 100k tonnes of greenhouse gases a year to reduce emissions intensity by 12 percent over the average emission levels of 2003, 2004 and 2005. Companies can make their reductions through improvements to their operations; by purchasing Alberta-based credits or by contributing to the Climate Change and Emissions Management Fund. Crescent Point does not operate any facilities that fall within this new requirement.

We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Our internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding.

Crescent Point believes it is in material compliance with environmental legislation in the jurisdictions in which it operates at this time. Crescent Point's practice is to do all that it reasonably can to ensure that it remains in material compliance with environmental protection legislation. Crescent Point also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. Crescent Point is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. Crescent Point anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given however that environmental laws will not result in a curtailment of production or a material increase in the costs of production, the development or exploration activities, or otherwise adversely affect Crescent Point's financial condition, capital expenditures, results of operations, competitive position or prospects.

RISK FACTORS

The following are certain risk factors relating to our business which prospective investors should carefully consider before deciding whether to purchase Trust Units.

Reserve Estimates

The reserve and recovery information contained in the Crescent Point Energy Trust Engineering Report are only an estimates and the actual production and ultimate reserves from our properties may be greater or less than the estimates prepared by GLJ and Sproule. Ultimately, actual reserves attributable to our properties will vary from estimates, and those variations may be material. The reserve figures contained herein are

only estimates. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- future commodity prices, production and development costs, royalties and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- success of future development activities;
- marketability of production;
- effects of government regulation; and
- other government levies that may be imposed over the producing life of reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the relevant evaluations were prepared. Many of these factors are subject to change and are beyond our control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates and such variations may affect the market price of our Trust Units and distributions to Unitholders.

Volatility of Oil and Natural Gas Prices

Our results of operations and financial condition are dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond our control. These factors include, but are not limited to, worldwide political instability, foreign supply of oil and natural gas, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels and the overall economic environment. Any decline in crude oil or natural gas prices may have a material adverse effect on our operations, financial condition, borrowing ability, reserves and the level of expenditures for the development of oil and natural gas reserves. Any resulting decline in our cash flow could reduce distributions.

We use financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from changes in natural gas and oil commodity prices. To the extent we hedge our commodity price exposure, we forego some of the benefits we would otherwise experience if commodity prices were to increase. In addition, our commodity hedging activities could expose us to losses. Such losses could occur under various circumstances, including where the other party to a hedge does not perform its obligations under the hedge agreement, the hedge is imperfect or our hedging policies and procedures are not followed. Furthermore, we cannot guarantee that such hedging transactions will fully offset the risks of changes in commodities prices.

In addition, we regularly assess the carrying value of our assets in accordance with Canadian generally accepted accounting principles under the full cost method. If oil and natural gas prices become depressed or decline, the carrying value of our assets could be subject to downward revision.

Operating Costs and Production Levels

An increase in operating costs or a decline in our production level could have a material adverse effect on our results of operations and financial condition and, therefore, could reduce distributions to Unitholders as well as affect the market price of the Trust Units.

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by the Trust and, therefore, may reduce distributions to our Unitholders. Electricity, chemicals, supplies, reclamation and abandonment and labour costs are a few of the operating costs that are susceptible to material fluctuation.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in our production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distributions to Unitholders.

Reinvestment of Cash Flow to Fund Ongoing Operations

Distributions may be reduced during periods in which we make capital expenditures or debt repayments using cash flow, which could also affect the market price of our Trust Units. To the extent that we use cash flow to finance acquisitions, development costs and other significant expenditures, the net cash flow that the Trust receives that is available for distribution to Unitholders will be reduced. Hence, the timing and amount of capital expenditures may affect the amount of net cash flow received by the Trust and, as a consequence, the amount of cash available to distribute to Unitholders. Therefore, distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

The board of directors of CPRI has the discretion to determine the extent to which cash flow from CPRI will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the credit facility. As a consequence, the amount of funds used to pay debt service charges or reduce debt will reduce the amount of cash available for distribution to Unitholders during those periods in which funds are so retained.

Marketing of Oil and Natural Gas Production

A decline in our ability to market our oil and natural gas production could have a material adverse effect on production levels or on the prices that we receive for our production which, in turn, could reduce distributions to Unitholders and affect the market price of our Trust Units.

Our business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, 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 change and inhibit the marketing of our production, overall production or realized prices may decline, which could reduce distributions to our Unitholders.

Fluctuations in Foreign Currency Exchange Rates

Fluctuations in foreign currency exchange rates could adversely affect our business, and could affect the market price of our Trust Units and distributions to Unitholders. The price that we receive for a majority of our oil and natural gas is based on United States dollar denominated benchmarks, and, therefore, the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given United States dollar price, negatively impacting future distributions and the future value of the Trust's reserves as determined by independent evaluators. We could be subject to unfavourable price changes to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

Acquisition of Additional Reserves

If we are unable to acquire additional reserves, the value of our Trust Units and distributions to Unitholders may decline. We do not actively explore for oil and natural gas reserves. Instead, we add to our oil and natural gas reserves primarily through development, exploitation and acquisitions. As a result, future oil and natural gas reserves are highly dependent on our success in exploiting existing properties and acquiring additional reserves. We also distribute the majority of our net cash flow to Unitholders rather than reinvesting it in reserve additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired. To the extent that we are required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distribution to Unitholders will be reduced. Additionally, we cannot guarantee that we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and as a consequence, either production from, or the average reserve life of, our properties will decline. Either decline may result in a reduction in the value of our Trust Units and in a reduction in cash available for distributions to Unitholders.

Scope of Operations

If we expand our operations beyond oil and natural gas production in western Canada, we may face new challenges and risks. If we were unsuccessful in managing these challenges and risks, our results of operations and financial condition could be adversely affected, which could affect the market price of our Trust Units and distributions to Unitholders.

Our operations and expertise are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities to oil and gas production and development, and we could acquire other energy related assets, such as oil and natural gas

processing plants or pipelines. Expansion of our activities into new areas may present challenges and risks that we have not faced in the past. If we do not manage these challenges and risks successfully, our results of operations and financial condition could be adversely affected.

Reliance on Reserve Estimates

In determining the purchase price of acquisitions, we rely on both internal and external assessments relating to estimates of reserves that may prove to be materially inaccurate. Such reliance could adversely affect the market price of our Trust Units and distributions to Unitholders.

The price we are willing to pay for reserve acquisitions is based largely on estimates of the reserves to be acquired. Actual reserves could vary materially from these estimates. Consequently, the reserves we acquire may be less than expected, which could adversely impact cash flows and distributions to Unitholders. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods and approaches than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments.

Operational Matters

Some of our properties are not operated by us and, therefore, results of operations may be adversely affected by the failure of third-party operators, which could affect the market price of our Trust Units and distributions to Unitholders.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of those properties. At December 31, 2007, approximately 15% of our daily production was from properties operated by third parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, our revenue may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements which govern the properties not operated by us typically require the operator to conduct operations in a good and “workmanlike” manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest owners, such as Unitholders, for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or wilful misconduct.

Delays in Business Operations

Delays in business operations could adversely affect distributions to Unitholders and the market price of our Trust Units. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, 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;
- restrictions due to limited pipeline capacity;
- 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 Unitholders in a given period and expose us to additional third party credit risks.

Debt Service

We may, from time to time, finance a significant portion of our operations through debt. Our indebtedness may limit the timing or amount of the distributions that are paid to Unitholders, and could affect the market price of our Trust Units.

The payments of interest and principal, and other costs, expenses and disbursements to our lenders reduces amounts available for distribution to Unitholders. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flow required to be applied to the debt before payment of any amounts to the Unitholders. The agreements governing our credit facility provide that if we are in default under the credit facility, exceed certain borrowing thresholds or fail to comply with certain covenants, we must repay the indebtedness at an accelerated rate, and the ability to make distributions to Unitholders may be restricted.

Our lenders have been provided with a security interest in substantially all of our assets. If we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may foreclose on and sell the properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for distribution to Unitholders.

Liquidity

Our current credit facility and any replacement credit facility may not provide sufficient liquidity. The amounts available under our existing credit facility may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. We currently have a syndicated \$740 million extendible revolving loan facility (the "Credit Facility") with certain banks and a \$60 million operating loan facility with one Canadian chartered bank. The interest charged on the Credit Facility is calculated based on a sliding scale ratio of the Trust's debt to cash flows. The Credit Facility is secured by the oil and gas assets owned by our wholly-owned subsidiaries. Repayment of all outstanding amounts under the syndicated credit facility may be demanded on relatively short notice. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and distributions to Unitholders may be materially reduced.

Competition

The oil and natural gas industry is highly competitive. We compete for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than we do. Some of these 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 worldwide basis. As a result of these complementary activities, some of our competitors may have greater and more diverse competitive resources to draw on than we do. Given the highly competitive nature of the oil and natural gas industry, this could adversely affect the market price of our Trust Units and distributions to Unitholders.

Operational Hazards and the Availability of Insurance

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance. Our operations are subject to all of the risks 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 include encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires and spills. A number of these risks could result in personal injury, loss of life, or environmental and other damage to our property or the property of others. We cannot fully protect against all of these risks, nor are all of these risks insurable. We may become liable for damages arising from these events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for distribution to Unitholders.

Environmental Concerns

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that Crescent Point may be in non-compliance with an environmental law, regulation, permit, licence, or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose Crescent Point to fines or penalties, third party liabilities or to the requirement to remediate, which could be material. The operational hazards associated with possible blowouts, accidents, oil spills, gas leaks, fires, or other damage to a well or a pipeline may require Crescent Point to incur costs and delays to undertake corrective actions, and could result in environmental damage or contamination for which Crescent Point could be liable. Oil and gas operations are also subject to specific operational risks which may have a material operational and financial impact on Crescent Point should they occur, such as drilling into unexpected formations or unexpected pressures; premature decline of reservoirs; and water invasion into producing formations.

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, which is intended to reduce emissions of pollutants into the air. Although we record a provision in our

financial statements relating to our estimated future environmental and reclamation obligations, we cannot guarantee that we will be able to satisfy our actual future environmental and reclamation obligations.

We are not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms.

Accordingly, our properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. Any site reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of our reclamation fund and, if required, out of cash flow and, therefore, will reduce the amounts available for distribution to Unitholders. Should we be unable to fully fund the cost of remedying an environmental problem, we might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

Unforeseen Title Defects

Unforeseen title defects may result in a loss of entitlement to production and reserves. Although we conduct title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat our title to the purchased assets. If such a defect were to occur, our entitlement to the production from such purchased assets could be jeopardized and, as a result, distributions to Unitholders may be reduced.

Aboriginal Land Claims

The economic impact on us of claims of aboriginal title is unknown. Aboriginal people have claimed aboriginal title and rights to a substantial portion of western Canada. We are unable to assess the effect, if any, that any such claim would have on our business and operations.

Changes in Tax and Other Laws

Changes in tax and other laws may adversely affect Unitholders. Income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource allowance, may in the future be changed or interpreted in a manner that adversely affects the Trust and Unitholders. Tax authorities having jurisdiction over the Trust or the Unitholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of Unitholders.

Loss of Mutual Fund Trust Status

There would be material adverse tax consequences if the Trust were to lose its status as a mutual fund trust under Canadian tax laws. It is intended that the Trust continue to qualify as a mutual fund trust for purposes of the Tax Act.

In order for the Trust to maintain its status as a mutual fund trust under the Tax Act, subject to certain exceptions, the Trust must not have been established or be maintained primarily for the benefit of non residents of Canada ("non residents") within the meaning of the Tax Act. Proposed amendments to the Tax Act originally announced by the Minister of Finance on March 23, 2004 provide that after December 31, 2004, subject to certain exceptions, the Trust must continuously ensure that not more than 50% of its issued Trust Units (based on fair market value) are held by non residents of Canada or partnerships (other than "Canadian partnerships" as defined in the Tax Act) (the "Proposal"). The Proposal was not included in the Notice of Ways and Means Motion tabled by the Minister of Finance on December 6, 2004 that implemented the proposed amendments announced on March 23, 2004, and, furthermore, the Minister of Finance issued a private letter stating that further work will be conducted by the Minister of Finance, including discussions with the private sector, to establish whether an alternative proposal should be devised that would achieve the underlying objectives of the Proposal without imposing absolute limits on non resident investments. In the February 23, 2005 federal budget, the Minister of Finance announced that a consultation paper was to be released shortly after the budget and that they would undergo a consultation process with stakeholders on the matter. Accordingly, it is uncertain whether the Proposal will be implemented at a later date as currently drafted, in substantially different form, or at all. Moreover, it is uncertain as to what different form, if any, a proposal to achieve the underlying objectives of the Proposal might take. The Trust Indenture provides that, if at any time the Trust becomes aware that the beneficial owners of 40% or more of the Trust Units then outstanding are or may be non residents or that such situation is imminent, the Trust will request declaration as to beneficial ownership at least annually. Furthermore, the Trust Indenture provides that if at any time the Trust becomes aware that the beneficial owners of 49% or more of the Trust Units then outstanding are or may be non residents or that such a situation is imminent, the Trust shall take such action as may be necessary to preserve mutual fund trust status. These measures could be adverse to certain Unitholders and may not be effective to avoid the Trust losing its status as a mutual fund trust for the purposes of the Tax Act.

If the Trust were not at present or at a future time to qualify as a mutual fund trust, the income tax considerations respecting the Trust and Unitholders may be materially different from those described in this summary, and in particular the following adverse income tax consequences may result:

- The Trust Units may cease to be qualified investments for Exempt Plans. Where at the end of any month an Exempt Plan holds non qualified investments, the Exempt Plan may be obligated to pay, with respect to that month, tax equal to 1% of the fair market value of such investments at the time such investments were acquired by the Exempt Plan. Where a trust governed by an RRSP or an RRIF acquires investments that are not qualified investments, the beneficiary of that trust will be deemed to have received taxable income in an amount equal to the purchase price of such investments, and while it holds investments that are not qualified investments, that trust will be taxable on its income attributable to such investments. Where a trust governed by a DPSP acquires investments that are not qualified investments the trust is liable for tax in an amount equal to the fair market value of such investments at the time of their acquisition. Where a trust governed by an RESP acquires investments that are not qualified investments or does not dispose of investments within 60 days of their ceasing to be qualified investments, the registration of the RESP may be revoked and the RESP will cease to be exempt from tax.
- The Trust will be required to pay a tax under Part XII.2 of the Tax Act in respect of amounts distributed to non resident persons. The payment of this tax by the Trust may have adverse income tax consequences for certain Unitholders, including non resident persons and tax exempt persons (including Exempt Plans) that acquire an interest in the Trust directly or indirectly from another Unitholder.
- The Trust will cease to be eligible for the capital gains refund mechanism available to mutual fund trusts.
- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

Income Tax Matters

Each of CPRI and the other corporate entities held directly or indirectly by the Trust (“Affiliates”) is subject to taxation in each taxation year on its income for the year, after deducting interest paid on any indebtedness. Each of CPRI and the Affiliates intends to deduct, in computing its income for tax purposes, the full amount available for deduction in each year associated with its income tax resource pools, undepreciated capital cost (“UCC”) and non-capital losses, if any. If there are not sufficient, current deductions, resource pools, UCC and non-capital losses carried forward to shelter the income of each of CPRI and the Affiliates, then cash taxes would be payable by CPRI and the Affiliates. Subsequent to the reorganization undertaken by the Trust and its Affiliates on March 1, 2007, it is not anticipated that any of the Affiliates will be subject to material income taxes.

In addition, oil and gas income trusts including this income trust generally rely on significant amounts of inter-entity debt, royalties or similar instruments, generating substantial interest expense or other deductions which serve to reduce taxable income and income tax payable during the life of the Trust. There can be no assurance that taxation authorities will not seek to challenge the amount of interest expense and other deductions. If such a challenge were to succeed against the Trust, it could materially adversely affect the amount and taxability of distributions available to Unitholders.

Income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts, may in the future be changed or interpreted in a manner that adversely affects the Trust and Unitholders. Tax authorities having jurisdiction over the Trust or the Unitholders may disagree with the manner in which the Trust calculates its income for tax purposes or could change their administrative practices to the detriment of the Trust or to the detriment of Unitholders. On June 22, 2007, the SIFT Rules were enacted into legislation and generally apply a tax at the trust level on distributions of business income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax rates and to treat such distributions as dividends to the Unitholders. The dividend deemed to be paid by trusts pursuant to the October 31 Proposals will be deemed to be an “eligible dividend” and would therefore benefit from the enhanced gross-up and dividend tax credit rules of the Tax Act. Existing trusts will have a four-year transition period and, subject to the qualification below, will not be subject to the new rules until 2011 providing existing trusts do not engage in “undue expansion”, discussed below.

The implementation of the SIFT Rules is expected to result in adverse tax consequences to the Trust and certain Unitholders (including most particularly Unitholders that are tax exempt or non-residents of Canada) and may impact cash distributions from the Trust. Taxation of the Trust’s distributions in 2011 and beyond will depend on the composition of its distributions which will vary depending on levels of profitability, available deductions, capital expenditures and other factors. It is therefore not possible to accurately predict the tax treatment for future years.

Furthermore, the SIFT Rules have reduced and may continue to adversely affect the value of the Units. A reduction in the value of the Units may increase the cost to the Trust of raising capital in the public capital markets. There can be no assurance that the Trust will be able to

reorganize its legal and tax structure to substantially mitigate the expected impact of the SIFT Rules. The Trust will continue to evaluate options available to continue its practice of minimizing taxes payable by the Trust and its Affiliates and enhancing value to Unitholders.

The SIFT Rules provided that the Trust will lose the transitional relief commencing from the beginning of the taxation year of the Trust in which it exceeds “normal growth” determined by reference to guidelines issued by the Department of Finance (federal) on December 15, 2006, as amended from time to time. As a result, the adverse tax consequences resulting from the proposals could be realized sooner than 2011. Specifically, the Department of Finance stated that “normal growth” would include equity growth (i.e. the issuance of new equity) within certain “safe harbour” limits, measured by reference to a trust’s market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of the trust’s issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% each for calendar years 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. Additional details of the Department of Finance’s guidelines include the following:

- (i) new equity for these purposes includes units and debt that is convertible into units (and may include other substitutes for equity if attempts are made to develop those);
- (ii) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion of convertible debentures into trust units or otherwise, will not be considered growth for these purposes and will therefore not affect the safe harbour; and
- (iii) the exchange, for trust units, of exchangeable partnership units or exchangeable shares that were outstanding on October 31, 2006 will not be considered growth for those purposes and will therefore not affect the safe harbour where the issuance of the trust units is made in satisfaction of the exercise of the exchange right by a person other than the trust.

The Trust does not believe that its near term growth opportunities will be significantly limited by the “normal growth” guidelines.

There can be no assurance that the SIFT Rules will not apply to the Trust prior to 2011.

Currently, the SIFT Rules provide that the tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011, and 15% in 2012) plus the provincial SIFT tax factor (which is set at a fixed rate of 13%), for a combined tax rate of 29.5% in 2011 and 28% in 2012.

On March 14, 2008, draft legislation (the “Provincial SIFT Tax Proposal”) received its first reading in the House of Commons, that would have the effect of instead of basing the provincial component of the tax on a flat rate of 13%, the provincial component will instead be based on the general provincial corporate income tax rate in each province in which the Trust has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, the Trust’s taxable distributions will be allocated to provinces by taking half of the aggregate of:

- that proportion of the Trust’s taxable distributions for the year that the Trust’s wages and salaries in the province are of its total wages and salaries in Canada; and
- that proportion of the Trust’s taxable distributions for the year that the Trust’s gross revenues in the province are of its total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal the Trust would be considered to have permanent establishments in Alberta, British Columbia, Saskatchewan and Manitoba, where the provincial tax rates in 2011 are expected to vary between 10% to 12% which will result in an effective tax rate of 26.5% to 28.5% in 2011 and 25% to 27% in 2012. Taxable distributions that are not allocated to any province would instead be subject to a 10% rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

Further, interest on indebtedness held at the Trust level accrues for income tax purposes whether or not actually paid. The Trust Indenture provides that an amount equal to the taxable income of the Trust will be distributed each year to Unitholders in order to reduce the Trust’s taxable income to zero. Where interest payments on indebtedness held by the Trust are due but not paid in whole or in part, the Trust Indenture provides that any additional amount necessary to be distributed to Unitholders may be distributed in the form of Units rather than in cash. Unitholders will be required to include such additional amount in income even though they do not receive a cash distribution.

Nature of Trust Units and the Trust

Rights as a Unitholder differ from those associated with other types of investments. The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in the Trust or CPRI. The Trust Units represent an equal fractional beneficial interest in the Trust and, as such, the ownership of the Trust Units does not provide Unitholders with the statutory rights normally associated with ownership of shares of a corporation, including, for example, the right to bring “oppression” or “derivative” actions. The unavailability of these statutory rights may also reduce the ability of Unitholders to seek legal remedies against other parties on our behalf.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have minimal value when reserves from our properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, cash distributions do not represent a “yield” in the traditional sense as they represent both return of capital and return on investment and the distributions received over the life of the investment may not meet or exceed the initial capital investment.

The Trust is a limited purpose unincorporated trust established under the laws of the Province of Alberta, which is governed by the terms and conditions of the Trust Indenture. As the Trust is not a corporate entity, it is not governed by the provisions of either provincial or federal corporate law. The Trust Units do not represent a traditional investment and should not be viewed by investors as “shares” in either CPRI or the Trust. As holders of Trust Units, Unitholders do 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 is not a legally recognized entity within the relevant definitions of the *Bankruptcy and Insolvency Act* (Canada), the *Companies’ Creditors Arrangement Act* (Canada) and in some cases, the *Winding Up and Restructuring Act* (Canada). As a result, in the event a restructuring of the Trust were necessary, the Trust would not be able to access the remedies available thereunder. In the event of a restructuring, a Unitholder may be in a different position than a shareholder of a corporation. The price per Trust Unit will be a function of anticipated distributable income and the ability to effect long term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions, including, but not limited to, interest rates, commodity prices and the ability of the Trust to acquire additional assets. Changes in market conditions may adversely affect the trading price of the Trust Units.

Market Factors

Changes in market-based factors may adversely affect the trading price of our Trust Units. The market price of our Trust Units is primarily a function of anticipated distributions to Unitholders and the value of our properties. The market price of our Trust Units is therefore sensitive to a variety of market based factors, including, but not limited to, interest rates and the comparability of our Trust Units to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Trust Units.

Loss of Key Personnel

Our operations are entirely independent from the Unitholders and loss of key management and other personnel could impact our business. Unitholders are entirely dependent on our management 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 our oil and natural gas properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team could have a detrimental effect on the Trust. Investors should carefully consider whether they are willing to rely on the existing management before investing in the Trust Units.

Dilution

There may be future dilution. One of our objectives is to continually add to our reserves through acquisitions and through development. Since we do not reinvest a material portion of our cash flow, our success is, in part, dependent on our ability to raise capital from time to time by selling additional Trust Units. Unitholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Trust Units issued to acquire those assets. Unitholders may also suffer dilution in connection with future issuances of Trust Units to effect acquisitions.

Availability of an Active Market for the Trust Units

There may not always be an active trading market for the Trust Units. While there is currently an active trading market for our Trust Units in Canada, we cannot guarantee that an active trading market will be sustained.

Unitholder Limited Liability

The limited liability of Unitholders is uncertain. Due to 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. Although every written contract or commitment of the Trust must contain an express disavowal of liability of the Unitholders and a limitation of liability to Trust property, such protective provisions may not operate to avoid Unitholder liability. Notwithstanding 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 the Unitholder resulting from or arising out of that Unitholder not having limited liability, the Trust cannot guarantee that any assets would be available in these circumstances to reimburse Unitholders for any such liability.

On July 1, 2004, the Province of Alberta proclaimed the *Income Trusts Liability Act* (Alberta) in force. This legislation provides that beneficiaries of Alberta based income trusts are not liable, as beneficiaries, for any act, default, obligation or liability of the income trust. Unitholders of the Trust have the benefit of this legislation with respect to liabilities arising on or after July 1, 2004.

Availability of Redemption Rights for Trust Units

The redemption rights of Unitholders is limited. Unitholders have a limited right to require the Trust to repurchase their Trust Units, which is referred to as a 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.

DISTRIBUTIONS

An objective of the Trust’s distribution policy is to provide Unitholders with relatively stable and predictable monthly distributions. An additional objective is to retain a portion of cash flow to fund ongoing development and optimization projects designed to enhance the sustainability of the Trust’s cash flow.

Although the Trust strives to provide Unitholders with stable and predictable cash flows, the percentage of cash flow from operations paid to Unitholders each month may vary according to a number of factors, including, fluctuations in resources prices, exchange rates and production rates, reserves growth, the size of development drilling programs and the portion thereof funded from cash flow and the overall level of debt of the Trust.

The actual amount of the distributions are at the discretion of our Board of Directors. In the event that commodity prices are higher than anticipated and a cash surplus develops, such surplus may be used to increase distributions, reduce debt and/or increase our capital program.

In 2007, the Trust’s payout ratio on a per Unit diluted basis was 68%.

The following table sets forth the amount of monthly cash distributions paid per Trust Unit by the Trust since September 2003.

	Distribution per Trust Unit
<u>2003</u>	
September.....	\$0.17
October.....	\$0.17
November	\$0.17
December	\$0.17
<u>2004</u>	
January	\$0.17
February.....	\$0.17
March	\$0.17
April	\$0.17
May.....	\$0.17
June	\$0.17
July.....	\$0.17

Distribution per Trust Unit

August.....	\$0.17
September.....	\$0.17
October	\$0.17
November	\$0.17
December	\$0.17
<u>2005</u>	
January	\$0.17
February	\$0.17
March.....	\$0.17
April.....	\$0.17
May	\$0.17
June	\$0.17
July	\$0.17
August.....	\$0.17
September.....	\$0.19
October.....	\$0.19
November	\$0.20
December	\$0.20
<u>2006</u>	
January	\$0.20
February.....	\$0.20
March.....	\$0.20
April	\$0.20
May.....	\$0.20
June	\$0.20
July.....	\$0.20
August.....	\$0.20
September.....	\$0.20
October.....	\$0.20
November	\$0.20
December.....	\$0.20
<u>2007</u>	
January	\$0.20
February.....	\$0.20
March.....	\$0.20
April	\$0.20
May.....	\$0.20

Distribution per Trust Unit

June	\$0.20
July.....	\$0.20
August.....	\$0.20
September.....	\$0.20
October.....	\$0.20
November	\$0.20
December	\$0.20
<u>2008</u>	
January	\$0.20
February.....	\$0.20
March ⁽¹⁾	\$0.20

Note:

(1) Payable April 15, 2008 to Unitholders of record on March 31, 2008.

The Trust makes cash distributions on the 15th day of each month (or the first business day thereafter) to Unitholders of record on the immediately preceding distribution record date.

MARKET FOR SECURITIES

The outstanding Trust Units are traded on the TSX under the trading symbol “CPG.UN”. The following table sets forth the price range and trading volume of the Trust Units as reported by the TSX for the periods indicated.

	<u>High (\$)</u>	<u>Low (\$)</u>	<u>Volume (000's)</u>
<u>2003</u>			
September ⁽¹⁾	12.20	11.46	3,980
October	12.20	11.90	2,319
November	12.39	11.90	2,820
December	13.75	12.20	1,960
<u>2004</u>			
January	14.00	13.19	2,858
February	14.55	13.00	2,606
March	15.75	14.30	2,002
April	15.95	14.90	1,404
May	15.40	14.26	2,283
June	15.00	13.70	1,610
July	15.00	14.70	1,421
August	15.46	14.90	1,694
September	16.80	14.99	2,094
October	17.75	16.00	3,296

	<u>High (\$)</u>	<u>Low (\$)</u>	<u>Volume (000's)</u>
November	18.25	16.25	3,200
December	17.80	16.55	2,152
 <u>2005</u>			
January	18.37	16.99	1,854
February	20.00	18.45	3,498
March	20.10	18.90	2,909
April	20.09	18.31	844
May	18.30	16.64	2,342
June	19.10	17.81	2,016
July	20.69	18.40	3,756
August	21.99	19.82	3,396
September	22.40	19.91	2,739
October	21.95	16.50	3,800
November	21.25	17.88	2,046
December	22.15	20.00	3,684
 <u>2006</u>			
January	21.75	20.36	6,842
February	22.20	19.00	6,007
March	23.00	21.26	6,200
April	23.73	22.10	2,870
May	22.93	20.40	3,833
June	22.64	20.10	4,765
July	23.00	21.52	4,796
August	23.91	22.35	4,223
September	23.50	17.55	13,138
October	20.90	16.06	11,805
November	18.35	15.08	18,797
December	18.26	16.96	7,163
 <u>2007</u>			
January	17.66	15.60	9,184
February	18.02	16.74	1,230
March	19.25	15.91	12,693
April	19.36	17.75	8,929
May	20.90	18.75	9,586

	<u>High (\$)</u>	<u>Low (\$)</u>	<u>Volume (000's)</u>
June	20.98	19.30	9,319
July	20.90	19.56	5,676
August	20.20	17.25	6,503
September	20.90	18.51	12,871
October	23.26	20.52	15,750
November	24.97	22.00	15,513
December	25.15	23.33	10,322

2008

January	25.45	21.06	13,383
February	27.50	23.90	8,763
March (1-28)	29.38	25.55	14,459

Note:

- (1) The Trust Units commenced trading on the TSX on September 10, 2003.

CONFLICTS OF INTEREST

Circumstances may arise where members of the board of directors or officers of CPRI are directors or officers of corporations which are in competition to the interests of CPRI and the Trust. No assurances can be given that opportunities identified by such board members or officers will be provided to CPRI or the Trust. In accordance with the *Business Corporation Act* (Alberta), a director or officer who is a party to a material contract or proposed material contract with CPRI or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with CPRI shall disclose to CPRI the nature and extent of the director's or officer's interest. In addition, a director shall not vote on any resolution to approve a contract of the nature described except in limited circumstances. Management of CPRI is not aware of any existing or potential material conflicts of interest between CPRI, the Trust or a subsidiary of the Trust and a director or officer of CPRI or any other subsidiary of the Trust.

Mr. Greg Turnbull, a director of CPRI and Mr. Mark Eade, an officer of CPRI, are each partners of McCarthy Tétrault LLP, a law firm that provides services to the Trust and its subsidiaries. The board of directors of CPRI do not believe that any of the activities undertaken by either of Messrs. Turnbull or Eade or by McCarthy Tétrault LLP interfere, or could be perceived to interfere, in any material way with their ability to act with a view to the best interests of the Trust and CPRI.

LEGAL PROCEEDINGS

There are no outstanding legal proceedings material to the Trust to which we are a party or in respect of which any of our properties are subject, nor are any such proceedings known to be contemplated.

AUDIT COMMITTEE

General

CPRI has established an Audit Committee (the "Audit Committee") comprised of three members: D. Hugh Gillard (Chair), Gerald A. Romanzin and Peter N. Bannister, each of whom is considered "independent" and "financially literate" within the meaning of Multilateral Instrument 52-110 – Audit Committees.

Mandate of the Audit Committee

The mandate of the Audit Committee is to assist the board or directors of CPRI in its oversight of the integrity of the financial and related information of the Trust, CPRI and their subsidiaries and related entities, including the financial statements, internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements. In doing so, the Audit Committee oversees the audit efforts of our external auditors and, in that regard, is empowered to take such actions as it may deem necessary to satisfy itself

that our external auditors are independent of us. It is the objective of the Audit Committee to have direct, open and frank communications throughout the year with management, other Committee chairmen, the external auditors, and other key committee advisors or CPRI staff members as applicable.

The Audit Committee's function is oversight. Management of CPRI is responsible for the preparation, presentation and integrity of the financial statements of the Trust and CPRI. Management is responsible for maintaining appropriate accounting and financial reporting principles and policy and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations.

While the Audit Committee has the responsibilities and powers set forth above, it is not the duty of the Audit Committee to plan or conduct audits or to determine whether the financial statements of the Trust and CPRI are complete and accurate and are in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors, on whom the members of the Committee are entitled to rely upon in good faith.

The Audit Committee Terms of Reference are attached hereto as Appendix A.

Relevant Education and Experience of Audit Committee Members

The following is a brief summary of the education or experience of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee, including any education or experience that has provided the member with an understanding of the accounting principles used by us to prepare our annual and interim financial statements.

Name of Audit Committee Member	Relevant Education and Experience
---------------------------------------	--

D. Hugh Gillard

Mr. Gillard has over thirty years of business experience in the oil and gas industry and is the Principal of Saddleback Resources Ltd., a private company involved in equity investments and advisory roles in the energy sector. From June 2003 to March 2006, he was President, Chief Executive Officer and a director of Kelso Energy Inc., a publicly traded junior oil and gas company. Kelso Energy Inc. subsequently merged with COSTA Energy Ltd. where he continued to serve as a director until December 2006. From 1999 to 2000 he was President, Chief Operating Officer and a director of PrimeWest Energy Trust. From 1990 to 1998, he was employed by CanWest Gas Marketing Inc., a private producer owned gas marketing company. During this period Mr. Gillard initially served as Vice President, Gas Supply and then later as President and Chief Executive Officer. From 1972 to 1989, he held several senior positions with Ashland Oil Canada, Dome Petroleum and Amoco Canada.

Mr. Gillard currently serves as a director of Creststreet Power Income Fund and as a director (Chairman) of Petrowest Energy Services Trust, both publicly traded entities. He also served as a director of Point North Energy Ltd. from October 2005 to November 2006. In September 2006, Point North Energy Ltd., filed for creditor protection due to circumstances arising from events which occurred prior to Mr. Gillard being appointed to the board. In September 2007, a successful plan of arrangement was approved and Point North Energy Ltd. emerged from Companies Creditors Act protection.

Mr. Gillard is a graduate of the University of Calgary (Commerce) and the Stanford Business School Executive Program. He is a past member of the Management Advisory Council (University of Calgary) and past Chairman of the Hospice Calgary Board of Directors.

Gerald A. Romanzin

Gerald Romanzin is an independent Calgary businessman who serves as a director of FET Resources Ltd., Petrowest Energy Services Ltd., Ketch Resources Ltd., Trimac Transportation Services Inc. and Kereco Energy Ltd. He also serves as a trustee of Trimac Income Fund. Mr. Romanzin was the Executive Vice President of the TSX Venture Exchange from November 1999 to April 2002 where he was responsible for overseeing the Corporate Finance group and regional operations. In addition, he assumed the role of Acting President of the TSX Venture Exchange from December 2001 to April 2002. Mr. Romanzin is a chartered accountant and was a financial analyst with the Alberta Securities Commission for four years prior to joining the Alberta Stock Exchange in 1987. Mr. Romanzin was the Executive Vice President of the Alberta Stock Exchange from June 1995 to its change to the TSX Venture Exchange in November 1999.

Mr. Romanzin obtained a Bachelor of Commerce degree from the University of Calgary and is a member of the Institute of Chartered Accountants of Alberta.

Peter N. Bannister

Peter Bannister is the President of Destiny Energy Inc., a privately-owned oil and gas company. Until its sale in February 2007, Mr. Bannister was Vice President Exploration and Director of Mission Oil and Gas Inc. Prior to joining Mission Oil and Gas Inc., he was Vice President Exploration of StarPoint Energy Inc. before its conversion to a royalty trust and President and a director of Impact Energy Inc. Mr. Bannister previously held the position of Vice President Corporate Development of Startech Energy until it was acquired by ARC Resources at the end of 2000 and also held positions as Vice President Exploration and Development and Director of both Boomerang Resources Ltd. and Laurasia Resources Limited, both publicly traded oil and gas companies. Mr. Bannister's experience prior to his involvement in public oil and gas companies was as a partner of Sproule Associates Limited, a worldwide petroleum consulting firm specializing in the evaluation of oil and gas properties where he spent 12 years specializing in oil and gas

Name of Audit Committee Member

Relevant Education and Experience

property evaluations and managing private equity investments in the oil and gas business in Western Canada. Mr. Bannister is also a director of Shelter Bay Energy Inc. and Breaker Energy Ltd.

A graduate of the University of Calgary in 1981 he holds a Bachelor of Science degree majoring in Geology with a minor in Economics. Mr. Bannister is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and has 27 years of oil and gas industry experience.

External Auditor Services Fees

For services provided to the Trust and its subsidiaries the years ended December 31, 2007 and 2006, PricewaterhouseCoopers LLP billed approximately \$376,228 and \$550,085, respectively, as detailed below:

	Year ended December 31	
	2007	2006
PricewaterhouseCoopers		
Audit fees	\$ 219,000	\$ 215,700
Audit-related fees ⁽¹⁾	\$ 154,515	\$ 328,785
Tax Fees	\$ 2,713	\$ 5,600
All Other Fees	\$ -	\$ -
Total	\$ 376,228	\$ 550,085

Note:

(1) Fees include the costs related to public financings and related reporting to regulators.

The Chairman of the Audit Committee has the authority to pre-approve non-audit services which may be required from time to time.

Audit Committee Oversight

At no time since the commencement of our most recently completed financial year, has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the board of directors of CPRI.

TRANSFER AGENT AND REGISTRARS

Our auditors are PricewaterhouseCoopers LLP, Chartered Accountants, 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3.

The transfer agent and registrar for our Trust Units is Olympia Trust Company in Calgary, Alberta.

MATERIAL CONTRACTS

Set out below are agreements that may be considered material to us:

1. Trust Indenture. See “*Additional Information Respecting the Trust*”.
2. Credit Facilities. See “*Additional Information Respecting the Trust – Credit Facilities*”.
3. Administration Agreement between the Trust and CPRI. See “*Additional Information Respecting CPRI – Administration Agreement*”.
4. Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan. See “*Additional Information Respecting the Trust – Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan*”.

INTERESTS OF EXPERTS

Reserve estimates contained in this annual information form are derived from reserve reports prepared by GLJ and Sproule. As of the date hereof, GLJ, as a group and Sproule, as a group, do not beneficially own, directly or indirectly, any Trust Units.

ADDITIONAL INFORMATION

Additional financial information is available on SEDAR at www.sedar.com and on our website at www.crescentpointenergy.com.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the issuer's securities, options to purchase securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in our information circular in respect of the annual and special meeting of Unitholders held on May 31, 2007. Additional financial information is provided in our comparative financial statements and management's discussion and analysis for our most recently completed financial year ended December 31, 2007.

For additional copies of this annual information form please contact:

Crescent Point Resources Inc
2800, 111 – 5th Avenue, S.W.
Calgary, Alberta
T2P 3Y6

Attention: Investor Relations

Appendix A

CRESCENT POINT RESOURCES INC. AUDIT COMMITTEE TERMS OF REFERENCE

I. The Board of Directors' Mandate for the Audit Committee

1. **The Board of Directors** ("Board") has responsibility for the stewardship of Crescent Point Resources Inc., Crescent Point Energy Trust (the "Trust") and subsidiaries or related entities (collectively referred to herein as the "Company"). To discharge that responsibility, the Board is obligated by the Alberta *Business Corporations Act* to supervise the management of the business and affairs of the Company. The Board's supervisory function involves Board oversight or monitoring of all significant aspects of the management of the Company's business and affairs.

Public financial reporting and disclosure by the Company are fundamental to the Company's business and affairs and to its status as a publicly listed enterprise. The objective of the Board's monitoring of the Company's financial reporting and disclosure is to gain reasonable assurance of the following:

- (a) that the Company complies with all applicable laws, regulations, rules, policies and other requirements of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;
- (b) that the accounting principles, significant judgements and disclosures which underlie or are incorporated in the Company's financial statements are the most appropriate in the prevailing circumstances;
- (c) that the Company's quarterly and annual financial statements and Annual Information Forms ("AIF") are accurate within a reasonable level of materiality and present fairly the Company's financial position and performance in accordance with generally accepted accounting principles ("GAAP"); and
- (d) that appropriate information concerning the financial position and performance of the Company is disseminated to the public in a timely manner in accordance with corporate and securities law and with stock exchange regulations.

The Board is of the view that monitoring of the Company's financial reporting and disclosure policies and procedures cannot be reliably met unless the following activities ("the Fundamental Activities") are conducted effectively:

- (i) the Company's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Company's financial transactions and properly certified;
- (ii) the internal financial controls are regularly assessed for effectiveness and efficiency;
- (iii) the Company's quarterly and annual financial statements are properly prepared by management to comply with GAAP; and
- (iv) the Company's quarterly and annual financial statements and Management Discussion and Analysis ("MD&A") are reported on by an external auditor appointed by the securityholders of the Company.

To assist the Board in its monitoring of the Company's financial reporting and disclosure and to conform to applicable corporate and securities law, the Board has established the Audit Committee (the "Committee") of the Board.

2. Role of the Committee

The role of the Committee is to assist the Board in its oversight of the integrity of the financial and related information of the Company, including its financial statements, the internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements and to review the independence, qualifications and performance of the external auditor of the Company. Management is responsible for establishing and maintaining those controls, procedures and processes and the Committee is appointed by the Board to review and monitor them.

3. Composition of Committee

- (a) **Size** - The Committee shall be appointed annually by the Board and consist of at least three members from among the directors of the Company.

- (b) **Qualifications** – All members of the committee (the “Members”) must be “unrelated directors” under the proposed Toronto Stock Exchange (“TSX”) guidelines and Multi-lateral Instrument 52-110. All Members must be “financially literate” (i.e., have the ability to read and understand a balance sheet, an income statement and a cash flow statement). At least one Member of the Committee should have “accounting or related financial expertise” (i.e., the ability to analyze and interpret a full set of financial statements, including the notes attached thereto, in accordance with Canadian GAAP).
- (c) The Board shall designate the Chairman of the Committee.
- (d) In the event of a vacancy arising in the Committee or a loss of independence of any Member, the Committee will fill the vacancy within six weeks or by the following annual securityholders’ meeting if sooner.

4. **Reliance on Experts**

In contributing to the Committee’s discharging of its duties under this mandate, each Member of the Committee shall be entitled to rely in good faith upon:

- (a) financial statements of the Company represented to him by an officer of the Company or in a written report of the external auditors to present fairly the financial position of the Company in accordance with GAAP; and
- (b) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

5. **Limitations on The Committee’s Duties**

In contributing to the Committee’s discharging of its duties under Terms of Reference, each Member shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in these Terms of Reference is intended, or may be construed, to impose on any Member a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee’s duties is monitoring and reviewing to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the objectives of the Company’s financial reporting are being met and to enable the Committee to report thereon to the Board.

II. **Audit Committee Terms of Reference**

These Terms of Reference outline how the Committee will satisfy the requirements set forth by the Board in its mandate.

6. **Operating Principles**

The Committee shall fulfill its responsibilities within the context of the following principles:

7. **Committee Values**

The Committee expects the management of the Company to operate in compliance with corporate policies; reflecting laws and regulations governing the Company; and to maintain strong financial reporting and control processes.

8. **Communications**

The Committee and its Members expect to have direct, open and frank communications throughout the year with management, other Committee Chairmen, the external auditors, and other key Committee advisors or Company staff members as applicable.

9. **Annual Audit Committee Plan**

The Committee, in consultation with management and the external auditors, shall develop an annual Audit Committee plan responsive to the Committee’s responsibilities as set out in these Terms of Reference. In addition, the Committee, in consultation with management and the external auditors, shall develop and participate in a process for review of important financial topics that have the potential to impact the Company’s financial disclosure.

The plan will be focused primarily on the annual and interim financial statements and MD&A of the Company; however, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the Committee’s Terms of Reference.

10. Meeting Agenda

Committee meeting agendas shall be the responsibility of the Chairman of the Committee in consultation with other Members, senior management and the external auditors.

11. Committee Expectations and Information Needs

The Committee shall communicate its expectations to management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at a reasonable time in advance of meeting dates.

12. Access to Independent Advisors

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditors, at the expense of the Company, retain one or more persons, firms or corporations having special expertise.

13. In Camera Meetings

At the discretion of the Committee, the Members shall meet in private session with the external auditors and with management only.

14. Reporting to the Board

The Committee, through its Chairman, shall report after each Committee meeting to the Board at the Board's next regular meeting.

15. Evaluation

The Committee will conduct and present to the Board an annual evaluation of the performance of the Committee and the adequacy of these Terms of Reference and recommend any proposed changes to the Board for approval.

16. The External Auditors

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditors shall be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues, either specific to the Company or to the financial reporting environment in general, to the Committee.

A. Operating Procedures

17. The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chairman, upon the request of two (2) Members or at the request of the external auditors.

18. A quorum shall be a majority of the Members.

19. Unless the Committee otherwise specifies, the Secretary (or his or her depute) of the Company shall act as Secretary of all meetings of the Committee.

20. In the absence of the Chairman of the Committee, the Members shall appoint an acting Chairman.

21. A copy of the minutes of each meeting of the Committee shall be provided to each Member and to each director of the Company in a timely fashion.

B. Specific Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

Financial Information and Reporting

22. Review, prior to public release, the Company's annual and quarterly financial statements with management and the external auditors to gain reasonable assurance that the statements are accurate within reasonable levels of materiality, complete, represent fairly the Company's financial position and performance and are in accordance with GAAP and report thereon to the Board before such financial statements are approved by the Board;

23. Receive from the external auditors reports on their review of the annual and quarterly financial statements;
24. Receive from management a copy of the representation letter provided to the external auditors and receive from management any additional representations required by the Committee;
25. Review, prior to public release, all news releases issued by the Company with respect to the Company's annual and quarterly financial statements; and
26. Review prospectuses, material change disclosures of a financial nature, management discussion and analysis, annual information forms and similar disclosure documents to be issued by the Company.

Accounting Policies

27. Review with management and the external auditors the appropriateness of the Company's accounting policies, disclosures, reserves, key estimates and judgments, including changes or variations thereto.
28. Obtain reasonable assurance that the accounting policies, disclosures, reserves, key estimates and judgments are in compliance with GAAP from management and external auditors and report thereon to the Board.
29. Review with management and the external auditors the degree of conservatism of the Company's underlying accounting policies, key estimates and judgments and reserves along with quality of financial reporting.
30. Participate, if requested, in the resolution of disagreements between management and the external auditors.

Risk and Uncertainty

31. Acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Company, determine the Company's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:
 - (a) reviewing with management the Company's tolerance for financial risks;
 - (b) reviewing with management its assessment of the significant financial risks facing the Company;
 - (c) reviewing with management the Company's policies and any proposed changes thereto for managing those significant financial risks; and
 - (d) reviewing with management its plans, processes and programs to manage and control such risks.
32. Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion.
33. Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments.
34. Review the adequacy of insurance coverages maintained by the Company.
35. Review regularly with management, the external auditors and the Company's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Company and the manner in which these matters have been disclosed in the financial statements.

Financial Controls and Control Deviations

36. Review the plans of the external auditors to gain reasonable assurance that the evaluation and testing of internal financial controls is comprehensive, coordinated and cost-effective.
37. Receive regular reports from management and the external auditors on all significant deviations from GAAP or other Company internal control processes or indications which may suggest fraud and the corrective activity undertaken in respect thereto.

38. Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Board or the Committee concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgement, through existing reporting structures in the Company.

Compliance with Laws and Regulations

39. Receive and review regular reports from management and others (e.g. external auditors) with respect to the Company's compliance with laws and regulations having a material impact on the financial statements including:
- (a) tax and financial reporting laws and regulations;
 - (b) legal withholding requirements; and
 - (c) other laws and regulations which expose directors to liability.
40. Review the filing status of the Company's tax returns and those of its subsidiaries or related entities.

Relationship with External Auditors

41. Recommend to the Board the nomination of the external auditors.
42. Pre-approve the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter. The Chairman of the Committee hereby has the authority to pre-approve non-audit services which may be required from time to time.
43. Review the performance of the external auditors annually or more frequently as required.
44. Receive annually from the external auditors an acknowledgement in writing that the securityholders, as represented by the Board and the Committee, are their primary client.
45. Receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non-audit services by the Company.
46. Review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ.
47. Meet with the external auditors at least once a year in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee.
48. Establish effective communication processes with management and the Company's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee.
49. Establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgement of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee of any disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

Relationship with Internal Auditor

50. Review the internal audit staff functions, including:
- (a) the purpose, authority and organizational reporting lines;
 - (b) the annual audit plan, budget and staffing; and
 - (c) the appointment and compensation of any person with the responsibility for the Internal Audit.
51. Review, with the Chief Financial Officer, controller or others, as appropriate, the Company's internal system of audit controls and the results of internal audits.

Other Responsibilities and Procedures

52. After consultation with the Chief Financial Officer and the external auditors, gain reasonable assurance, at least annually, of the quality and sufficiency of the Company's accounting and financial personnel and other resources.
53. Investigate any matters that, in the Committee's discretion, fall within the Committee's duties.
54. Perform such other functions as may from time to time be assigned to the Committee by the Board.

Hiring Guidelines for Independent Auditor Employees

55. The Committee has adopted the following guidelines regarding the hiring of any partner, employee, reviewing tax professional or other person providing audit assurance to the external auditor of the Company on any aspect of its certification of the Company's financial statements:
 - (a) No senior member of the audit team that is auditing a business of the Company can be hired into that business or into a position to which that business reports for a period of two years after the audit.
 - (b) No former partner or employee of the external auditor may be made an officer of the Company or any of its subsidiaries for two years following association with the external auditor.
 - (i) The Chief Executive Officer must approve all office hires from the external auditor.
 - (ii) The Chief Financial Officer must report annually to the Committee on any hires within these guidelines during the preceding year.

Audit Partner Rotation

56. The Committee will ensure that the head audit partner assigned by the external auditor to the Company, as well as the audit partner charged with reviewing the audit of the Company, are changed at least every five years.

Process for Handling Complaints about Accounting Matters

57. The Committee will establish the following procedure for the receipt and treatment of any complaint received by the Company regarding accounting, internal accounting controls or auditing matters:
 - (a) The Company will publish on its website special mail and e-mail addresses and a toll free telephone number for receiving complaints regarding accounting, internal accounting controls or auditing matters.
 - (b) Copies of complaints received will be sent to the Members of the Committee.
 - (c) All complaints will be investigated by the Company's finance and legal staffs in the normal manner, except as otherwise directed by the Committee. The Committee may request that outside advisors be retained to investigate any complaint.
 - (d) The status of each complaint will be reported on a quarterly basis to the Committee and, if the Committee so directs, to the full board.

Appendix B

CRESCENT POINT RESOURCES INC. RESERVES COMMITTEE TERMS OF REFERENCE

1. Reserves Committee Purpose

The Reserves Committee (the “Committee”) is appointed by the Board of Directors (the “Board”) to assist the Board in fulfilling its responsibility for the stewardship of Crescent Point Resources Inc., Crescent Point Energy Trust (the “Trust”) and subsidiaries or related entities (collectively referred to herein as the “Company”). The Committee’s primary duties and responsibilities are to assume responsibility for assisting the Board in respect of the annual independent review of the Trust’s petroleum and natural gas reserves and reporting to the Board in respect thereof.

2. Reserves Committee Composition, Procedures and Organization

The Committee shall consist of at least two directors as determined by the Board, the majority of whom shall be independent (as required by National Instrument 51-101). Committee members shall also meet the independence requirements of the regulatory bodies to which the Company may be subject to. The Board shall appoint the members of the Committee and may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee. If a Committee Chair is not designated by the Board, or is not present at a meeting of the Committee, the members of the Committee may designate a chair by majority vote of the Committee membership. The Secretary of the Company, shall act as Secretary of the Committee. The quorum for meetings shall be a majority of the members of the Committee present in person or by telephone or other telecommunications device that permits all persons participating in the meeting to speak and to hear each other. The Committee shall meet at least annually at such times and at such locations as may be requested by the chair of the Committee and at such times as any member of the Committee may request.

3. Reserves Committee Responsibilities and Duties

The overall duties and responsibilities of the Committee shall be as follows:

- in conjunction with the Company’s senior engineering management, meet with the independent evaluating engineers being considered for appointment to review their qualifications and independence to ensure the independent evaluating engineers being considered for appointment are technically qualified and competent, are independent of management and to establish the terms of their engagement;
- after consultation with the Company’s senior engineering management, recommend to the Board the appointment of the independent evaluating engineers to assist the Company in the annual review of its petroleum and natural gas reserves;
- in consultation with the Company’s senior engineering management determine the scope of the annual review of the petroleum and natural gas reserves by the independent evaluating engineers, having regard to regulatory reporting requirements;
- review, with reasonable frequency, the Company’s procedures for providing petroleum and natural gas reserves information to the qualified independent evaluating engineers who report on reserves data for the purposes of National Instrument 51-101, and the information used by the independent evaluating engineers to enable the independent evaluating engineers to provide a report that will meet regulatory reporting requirements;
- in consultation with the Company’s senior engineering management and the independent evaluating engineers:
 - determine whether any restrictions affect the ability of the independent evaluating engineers to report on reserve data without reservations; and
 - review the reserves data and the report of the independent evaluating engineers.
- ensure the disclosure to the public on the Company’s petroleum and natural gas reserves is in compliance with regulatory requirements;
 - review any proposal to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;
 - meet on an annual basis with the Company’s senior engineering management and/or the independent evaluating engineers of the Company to review and consider the evaluation of the Company’s petroleum and natural gas reserves;
 - meet separately with the independent evaluating engineers and/or senior engineering management when the Committee

deems it desirable and advise the Board on the results of such meeting;

- co-ordinate meetings with the Audit Committee of the Company, the Company's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Company's evaluation of petroleum and natural gas reserves;
- review annually the Committee charter and recommend any changes to the Board; and
- to maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

Appendix C

FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Crescent Point Energy Trust (the "Company"):

1. We have prepared an evaluation of the Trust's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.
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, 2007, 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 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, 2008	Canada	-	\$1,161,620	-	\$1,161,620

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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 7, 2008

ORIGINALLY SIGNED BY

Terry L. Aarsby, P. Eng.
Vice President

**FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR**

To the board of directors of Crescent Point Energy Trust (the "Company"):

1. We have prepared an evaluation of the Company's Reserve Data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.
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 presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us as of December 31, 2007, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation of the P&NG Reserves of Crescent Point Energy Trust, as of December 31, 2007, prepared December 2007 to February 2008	Canada	Nil	2,510,491	Nil	2,510,491

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook.
6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, Canada

Dated February 22, 2008

ORIGINALLY SIGNED BY

Douglas R. Bates, P.Eng.
Associate

Michael W. Maughan, C.P.G., P.Geol.
Vice President, Geoscience

Robert N. Johnson, P. Eng
Vice President, Engineering

Appendix D

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Crescent Point Energy Trust (the "Trust") are responsible for the preparation and disclosure of information with respect to the Trust's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2007 using forecast prices and costs; and
- (a) (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2007 using constant prices and costs; and
- (b) (ii) the related estimated future net revenue.

GLJ Petroleum Consultants and Sproule Associates Limited, each an independent qualified reserves evaluator have evaluated the Trust's reserves data. The reports 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 Trust has

- (c) reviewed the Trust's procedures for providing information to the independent qualified reserves evaluators;
- (d) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
- (e) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors has reviewed the Trust'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 Form 51-101F1 containing the reserves data and other oil and gas information;
- (g) the filing of Form 51-101F2 which is the reports of the independent qualified reserves evaluators on the reserves data; and
- (h) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

"Scott Saxberg"

Scott Saxberg

President and Chief Executive Officer

"C Neil Smith"

C Neil Smith

Vice President, Engineering and Business Development

"Paul Colborne"

Paul Colborne

Director

"Peter Bannister"

Peter Bannister

Director

March 31, 2008