PARAMOUNT ENERGY TRUST

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2006

DATED: March 13, 2007

TABLE OF CONTENTS

ABBREVIATIONS

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units
GJ	gigajoule

Words importing the singular also include the plural, and *vice versa*, and words importing one gender include all genders. All dollar amounts set forth in the annual information form are in Canadian dollars, except where otherwise indicated.

CONVERSION

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in the annual information form constitute forward-looking statements. These statements relate to future events or to our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of the words “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “should”, “believe”, “predict”, “targeting”, “seek”, “intend”, “could”, “potential”, “should” and similar expressions. 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. We 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. Such forward-looking statements included in the annual information form should not be unduly relied upon. These statements speak only as of the date of the annual information form. In particular, the annual information form contains forward-looking statements pertaining to the following:

- the size of our natural gas reserves;
- estimates of future cash flow and distributions;
- projections of market prices and costs and the related sensitivities to distributions;

- natural gas production levels;
- capital expenditure programs;
- supply and demand for natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions, exploration and development; and
- treatment under governmental regulatory regimes, both existing and proposed.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set out below and elsewhere in the annual information form:

- volatility in market prices for natural gas;
- liabilities inherent in natural gas operations;
- adverse regulatory rulings, orders and decisions;
- uncertainties associated with estimating natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves and undeveloped lands, service providers and skilled personnel;
- incorrect assessments of reserves and the value of acquisitions;
- geological, technical, drilling and processing problems; and
- the other factors discussed under **RISK FACTORS**

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this annual information form are expressly qualified by this cautionary statement. None of PET, the Administrator nor POT (each defined below) undertakes any obligation to publicly update or revise any forward-looking statements unless expressly required to do so by applicable securities laws. Further, readers should also carefully consider the matters discussed under the heading **RISK FACTORS** in this annual information form.

NON-GAAP MEASURES

In this annual information form, we use funds flow from operations before changes in non-cash working capital ("cash flow") and cash flow per Trust Unit to analyze operating performance and financial leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore it may not be comparable to the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Cash flow cannot be assured and future distributions may vary. All references to "cash flow" are based on cash flow before changes in non-cash working capital related to operating activities, certain exploration costs and settlement of asset retirement obligations. A reconciliation of cash flow to cash flow from operating activities is presented in our management's discussion and analysis. We use the term "cash flow" as an indicator of financial performance because the term "cash flow" is commonly utilized by investors to evaluate royalty trusts and income funds in the oil and gas sector.

PARAMOUNT ENERGY TRUST STRUCTURE

Paramount Energy Trust ("**PET**", the "**Trust**", "**us**", "**we**" or "**our**" and, where the context requires, also includes our subsidiaries) is an unincorporated trust established on June 28, 2002 under the laws of the province of Alberta under a trust indenture among Computershare Trust Company of Canada as trustee (the "**Trustee**"), BMO Nesbitt Burns Inc. and Paramount Energy Operating Corp. (the "**Administrator**"). This trust indenture was subsequently amended and restated effective as of August 1, 2002 (the "**Trust Indenture**"). Our assets consist primarily of the POT Royalty (defined below), certain debt owing by Paramount Operating Trust ("**POT**") to us, 100% ownership of the Administrator and 100% ownership of the beneficial interest in POT.

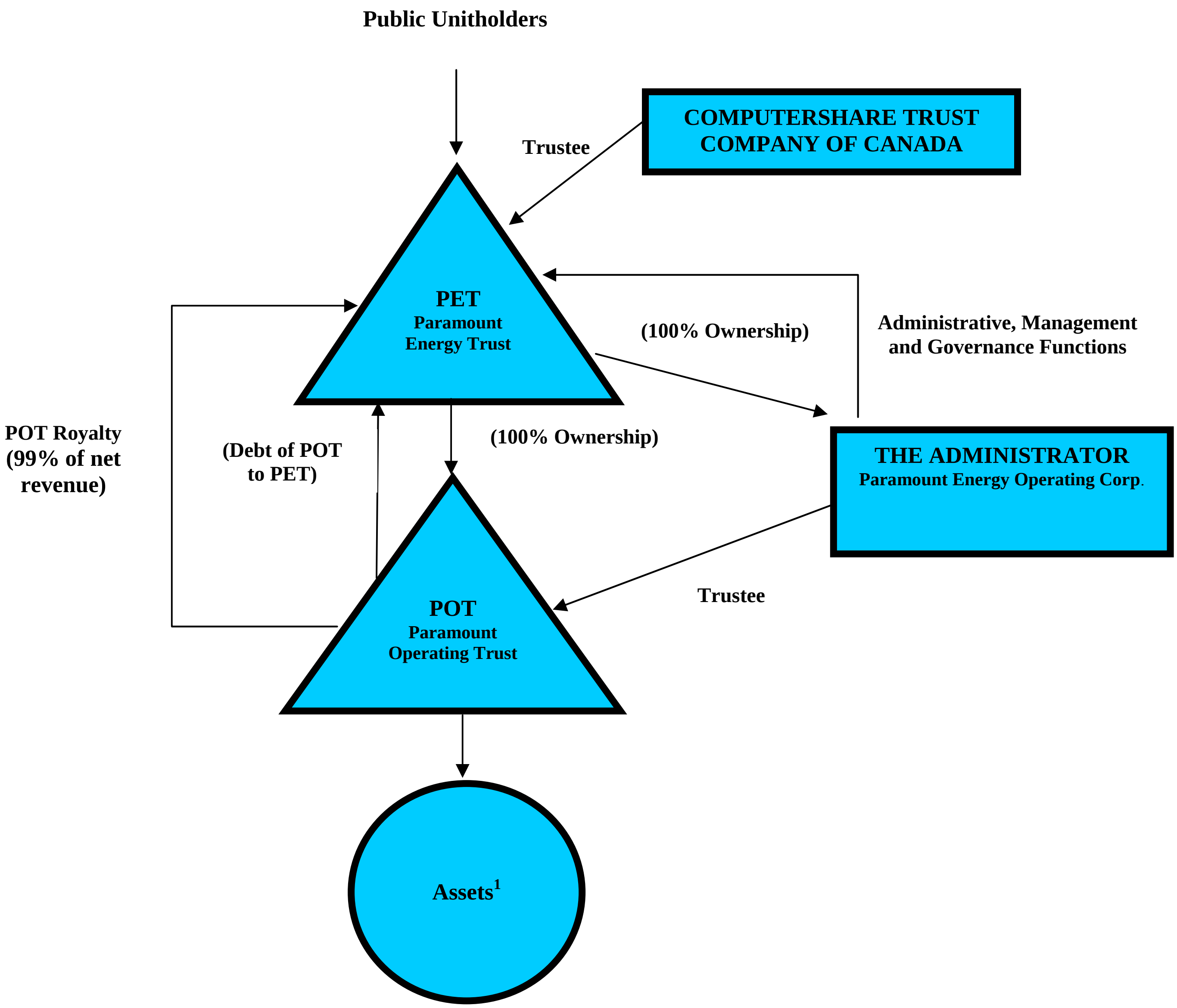
We were established for the purposes of issuing trust units ("**Trust Units**") and acquiring and holding royalties and other investments including the entire beneficial interest in POT and the POT Royalty (defined below). We effectively finance the operations of POT. We make cash distributions to holders of Trust Units ("**Unitholders**"). These distributions are comprised of royalty and interest income from POT, if any, less any expenses and any other amounts that must be withheld or paid to third parties. All Trust Units outstanding from time to time are entitled to an equal undivided share of any distributions. Under the Trust Indenture, we have broad powers to invest funds that are not distributed to Unitholders.

POT is an unincorporated trust established on June 28, 2002 under the laws of the province of Alberta under a trust indenture between the Administrator as trustee and CIBC World Markets Inc. as settlor with PET as its sole beneficiary. This trust indenture was subsequently amended and restated effective as of August 1, 2002 (the "**POT Indenture**"). POT holds, directly and indirectly, all of the oil and natural gas properties in the trust structure on PET's behalf. POT's business is acquiring, exploring, developing, producing, optimizing and disposing of oil and natural gas properties. Under an agreement between POT as grantor and PET as royalty owner (the "**POT Royalty Agreement**"), POT pays PET 99% of POT's net revenue from its oil and natural gas properties less permitted deductions with respect to debt payments, capital expenditures and certain other amounts (the "**POT Royalty**").

The Administrator was incorporated on June 28, 2002 under the *Business Corporations Act* (Alberta) ("**ABCA**"). All of the issued and outstanding shares of the Administrator are held in the name of the Trustee for our benefit and on our behalf. The Administrator was formed primarily to act as trustee of POT and to administer, manage and operate the oil and gas business of POT. In addition, the Trustee has, in accordance with the Trust Indenture, delegated to the Administrator the significant management, administrative and governance functions with respect to PET. Much like a traditional oil and gas corporation, only costs incurred by or on behalf of the Administrator to operate the business will ultimately be borne by the Unitholders.

The head offices of PET, POT and the Administrator are located at 500, 630 – 4th Avenue S.W., Calgary, Alberta. The Administrator's registered office is located at 500, 630 – 4 Ave. SW, Calgary, Alberta.

The following diagram illustrates the current organizational structure of PET including the material operating subsidiaries of the Trust, the flow of funds from those operating subsidiaries to the Trust and the percentage of voting securities owned:



Note:

(1) Our assets are directly held by Paramount Operating Trust and several corporations and partnerships. POT is PET's only principal subsidiary, holding total assets that exceed 10 percent of our total consolidated assets or revenues as at and for the year ended December 31, 2006.

GENERAL DEVELOPMENT OF THE BUSINESS

Four Year History

Formation of the Trust

In April and May of 2002, the board of directors of Paramount Resources Ltd. ("**PRL**") gave its initial approval to the formation and structuring of a trust to hold a number of mature producing properties of PRL. Pursuant to the proposal, PRL would distribute the units of such trust to the holders of its common shares ("**PRL Common Shares**") through a dividend-in-kind. The mature, net cash generating, producing properties to be transferred to the trust were considered to be suitable for a trust and management of PRL believed the transaction would be financially beneficial to shareholders of PRL. In January of 2003, the board of directors of PRL gave its final approval to the transaction and to the final Canadian prospectus and U.S. registration statement of PET which were prepared to facilitate the transaction. The following transactions were completed on February 3, 2003:

- POT acquired PRL's natural gas properties and facilities in the Legend, Alberta area (the "**Initial Assets**") in exchange for the issuance by POT to PRL of an $81 million promissory note. POT assumed all risks on these assets and revenues and expenses associated with these assets accrued to POT for POT's account, effective July 1, 2002;

- PRL and POT entered into a purchase and sale agreement under which POT agreed to acquire from PRL up to 100% of PRL's interests in most of its remaining natural gas properties in northeast Alberta (the "**Additional Assets**"); and

- POT entered into the POT Royalty Agreement with PET effective July 1, 2002. As a result of a number of steps completed in connection with the payment of the consideration for the POT Royalty, PET issued 9,909,766 Trust Units to PRL and acquired the remaining $16,848,000 in indebtedness that POT owed to PRL.

The board of directors of PRL declared and, on February 12, 2003, paid a dividend-in-kind to the holders of PRL Common Shares of all of the Trust Units PRL received pursuant to the above transactions on the basis of one Trust Unit for each 6.071646 PRL Common Share held as of February 11, 2003.

The Trust Units commenced trading on the TSX on a when-issued basis on February 7, 2003.

On February 15, 2003, we issued to our Unitholders three transferable rights (referred to in this part as "**Rights**"), qualified by our prospectus dated January 29, 2003 for every Trust Unit held of record on February 14, 2003. Each Right entitled the holder to acquire one Trust Unit for a price of $5.05 until March 10, 2003. All of the Trust Units offered under this Rights offering were subscribed for. As a result, on March 11, 2003 PET issued an aggregate of 29,728,609 Trust Units pursuant to the exercise of the Rights and received net aggregate subscription proceeds of $150.1 million.

On March 11, 2003, we utilized the Rights subscription proceeds and the proceeds of bank financing arranged by us to repay $30.1 million owing to PRL and to acquire from PRL 100% of PRL's interest in the natural gas assets and facilities provided for in the purchase and sale agreement referred to above for a cash purchase price of $220 million. POT assumed all risks on these assets and revenues and expenses associated with these assets accrued to POT for POT's account, effective July 1, 2002. These acquisitions from PRL constituted a "significant acquisition" as that term is defined under applicable Canadian securities legislation.

Equity Financings

On May 30, 2003 we completed a bought-deal equity financing raising net proceeds of $60.1 million for the issuance of 5,000,000 Trust Units at $12.65 per Trust Unit. These proceeds were initially used to reduce bank debt and to partially fund our 2003 capital expenditure program.

On May 18, 2004, we completed a bought-deal equity financing raising net proceeds of $47.9 million for the issuance of 4.5 million Trust Units at $11.20 per Trust Unit. These proceeds were initially used to reduce bank debt and to fund a portion of our 2004 capital expenditure program.

Marten Hills Acquisition

On February 5, 2004, PET completed the acquisition of producing natural gas properties in the Marten Hills area of northeast Alberta for $30.3 million, effective January 1, 2004. The acquisition was financed from existing credit facilities.

Cavell Acquisition

We completed the acquisition of all the issued and outstanding shares of Cavell Energy Corporation ("**Cavell**") for $30 million and the issuance of 6,931,633 Trust Units effective July 16, 2004. This company's assets were 100% natural gas in southwest and west central Saskatchewan as well as in Mitsue, Alberta.

On August 24, 2004, we disposed of the southeast Saskatchewan assets acquired in the Cavell acquisition (described below) for $32.75 million, reinstating our natural gas weighting to virtually 100 percent.

Athabasca Acquisition

We completed an indirect acquisition of natural gas assets in northeast Alberta (Athabasca region) for $208.3 million ($197 million net of adjustments to the effective date of July 1, 2004).

In conjunction with the Athabasca acquisition, we completed a bought-deal equity financing on August 10, 2004 of 7,795,547 subscription receipts at a price of $12.35 per subscription receipt for gross proceeds of $96,275,005 and $48,000,000 aggregate principal amounts of 8.0% convertible extendable unsecured subordinate debentures (the "**8% Convertible Debentures**") with a conversion price of $14.20 per Trust Unit.

Northeast Alberta Acquisition and Equity Financing

On May 17, 2005, we completed the acquisition of natural gas assets in northeast Alberta (the "**Northeast Alberta Assets**") for $272.5 million effective January 1, 2005. In conjunction with the acquisition of the Northeast Alberta Assets, we completed an issue on April 26, 2005 by way of short form prospectus of 9,500,000 subscription receipts at a price of $16.85 per subscription receipt for gross proceeds of $160,075,000 and $100,000,000 aggregate principal amounts of 6.25% convertible extendible unsecured subordinated debentures (the "**2005 6.25% Convertible Debentures**") with a conversion price of $19.35 per Trust Unit.

East Central Alberta Acquisition

In February 2006, PET completed the acquisition of a private Alberta company for $92 million, adding operated, high-netback shallow gas production in east-central Alberta. The acquisition also provided the Trust with 60,700 net acres of year-round access undeveloped land in east central Alberta and over 50 defined prospects which meet PET's risk profile.

Convertible Debenture Financing

We completed an issue on March 30, 2006 by way of short form prospectus of $100,000,000 aggregate principal amounts of 6.25% convertible extendible unsecured subordinated debentures (the "**2006 6.25% Convertible Debentures**") with a conversion price of $23.80 per Trust Unit.

Internal Restructuring

In the third quarter of 2006, PET completed an internal restructuring in order to facilitate the development of certain assets south of its Athabasca core area. Assets producing approximately 1.4 MMcf/d were transferred to a private company, Severo Energy Corp. ("**Severo**"), which is 94% indirectly owned by PET.

Income Tax Proposals

On December 21, 2006, the Federal Minister of Finance of Canada released draft legislation to implement proposals originally announced on October 31, 2006 relating to the taxation of certain distributions from certain trusts and partnerships (the "October 31 Proposals"). Subject to the October 31 Proposals, returns on capital are generally taxed as ordinary income or as dividends in the hands of a Unitholder who is resident in Canada pursuant to the *Income Tax Act* (Canada) (the "Tax Act"). As called for in the October 31 Proposals, which were brought into law through a Ways and Means motion in early November 2006, commencing January 1, 2011 certain distributions from the Trust which would otherwise have been taxed as ordinary income generally will be characterized as dividends in addition to being subject to tax at a rate of 31.5 percent at the Trust level prior to distribution. Returns of capital generally are tax-deferred for Unitholders who are resident in Canada pursuant to the Tax Act. Under the October 31 Proposals, returns of capital will continue to be tax-deferred and will reduce Unitholders' adjusted cost base in the Trust Units for purposes of the Tax Act. Distributions, whether of income or capital to a Unitholder who is not resident in Canada for purposes of the Tax Act, or that is a partnership that is not a "Canadian partnership" for purposes of the Tax Act, generally will be subject to Canadian withholding tax.

'Safe harbour' rules outlined by the draft legislation will restrict growth for trusts over the four year transition period, with any new issues of equity limited to a trust's equity value on October 31, 2006. The Trust's market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding publicly-traded Trust Units, was approximately $1.4 billion, which means the Trust's "safe harbour" equity growth amount for the period ending December 31, 2007 is approximately $560 million, and for each of calendar 2008, 2009 and 2010 is an additional approximately $280 million, not including equity issued to replace debt that was outstanding on October 31, 2006, including convertible debentures.

These guidelines have adversely affected the price of Trust Units, thereby impacting both access to and the cost of raising capital. This could impact the Trust's ability to undertake significant acquisitions. It is not known at this time when the October 31 Proposals will be enacted by Parliament or whether the October 31 Proposals will be enacted in the form currently proposed. See **RISK FACTORS.**

On February 28, 2007, the House of Commons Standing Committee on Finance delivered its report to Parliament on the proposed taxation of income trusts. The report summarizes written submissions and oral presentations received by the Committee from more than 100 groups and individuals representing a wide range of stakeholders.

The Committee concluded that while elements of the tax proposals could contribute to its goal of a fair and neutral tax system that promotes growth and competitiveness, additional actions are needed. Consequently, the following three recommendations were made by the Committee:

1) The federal government should release the data and methodology it used to estimate the amount of federal tax revenue loss caused by the income trust sector.

2) The federal government should separate the proposal to tax income trusts from the other sections of the Ways and Means Motion (i.e. pension income splitting, the 0.5% reduction in the corporate tax rate in 2011 and the increase in the age credit amount) and table it in a stand-alone piece of legislation for Members of Parliament to vote on.

3) The federal government should implement one of the two following strategies:

   a. Reduce the proposed distribution tax to 10% from 31.5% (instituted immediately, but refundable to all Canadian investors), but continue the moratorium on new trust conversions while remaining open to representations from sectors that feel they may be well suited to the trust structure.

   b. Extend the proposed transition period to 10 years from four years.

The Government of Canada has not yet responded to this report.

Recent Developments

On February 28, 2007 PET entered into an agreement to acquire certain oil and gas properties in northeast Alberta for $46.5 million. The transaction is expected to close in late March 2007 and will be financed from available credit facilities.

DESCRIPTION OF THE BUSINESS

Business Plan

Summary

Our goal is to provide Unitholders with a vehicle through which we can distribute income and add value through the exploitation of current assets, low exposure exploration of our undeveloped land base and prudent acquisitions of additional lands and assets. Our business plan is based on four pillars: Asset Optimization; Cash Flow Maximization; Accretive Acquisitions and Balance Sheet Strength.

Asset Optimization

The Trust's asset base is comprised of properties in four core areas: West Side, East Side, Athabasca (all in northeast Alberta) and the Southern Core Area (with properties in East Central and Southern Alberta as well as Southwest Saskatchewan. Most fields are characterized by long production histories and gas wells have demonstrated a predictable decline in production as reserves have been produced over the years. The assets are comprised of natural gas properties that require relatively low capital reinvestment to offset natural production declines. We anticipate that cash flow from our assets will be sufficient to fund production, administrative expenses, interest expenses and capital expenditures and to permit us to accumulate working capital for our ongoing operations and distributions to Unitholders.

Capital expenditures target workovers, facility optimization activities, completion of secondary objectives in existing well bores, and drilling low risk development and low exposure exploration wells to maximize production and cash flow. Our assets host significant opportunities to add value that fit our conservative definition of acceptable risk. In addition, our ownership of processing and transportation facilities and large consolidated acreage position allow us to realize operating synergies and maintain operating costs near their current levels. We intend to maximize the value of undeveloped land with opportunities that do not meet our risk/reward hurdles by entering into farm out or other arrangements with third parties under which the third party will provide exploration funding in exchange for an earned interest or by swapping properties for other assets or equity in other entities, or by selling properties.

Cash Flow Maximization

Our internal marketing group markets production from our assets with a view to optimizing gas netbacks by seeking out the best markets. Direct marketing arrangements and pipeline transportation contracts are monitored closely to align actual usage with contractual obligations. We maximize the value of our assets by optimizing the natural gas production while minimizing costs thus maximizing netbacks. Many of the office, technical and field operations staff responsible for operating and managing our current assets have done so for a number of years.

Accretive Acquisitions

In addition to pursuing the acquisition of other properties in our core areas we intend to continue to seek corporate and property acquisition opportunities focused on natural gas. Future acquisition opportunities may lead to additional geographical and/or commodity diversification. The primary objective is the creation of value for Unitholders and, as such, we will target acquisitions that are accretive to net asset value and cash flow per Trust Unit and which increase our reserve and production base on a per Trust Unit basis. We will continue to target the acquisition of high quality assets with substantial low risk development potential and low capital requirements. We will not limit our acquisitions by commodity or geography although we intend to continue our focus on natural gas assets and our focus in our Northeast Alberta and Southern core areas. We plan to finance acquisitions through debt and equity financings. We are normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. As of the date of the annual information form, we have not reached agreement on the price or terms of any potential future acquisition except as described under **GENERAL DEVELOPMENT OF THE BUSINESS - *Recent Developments***. We cannot predict whether any current or future opportunities will result in one or more acquisitions being completed.

Healthy Balance Sheet

We strive to maintain a healthy balance sheet, recognizing the cyclical nature of commodity prices and the oil and gas business. This prepares us to pursue new opportunities to add value for our Unitholders as they arise throughout the commodity price cycles.

Environment, Health and Safety (EH&S)

Safety is our number one priority at PET. Our core values of accountability and integrity support our strong commitment to both compliance with applicable legislation, and achievement of high standards of workplace health and safety and environmental stewardship throughout all phases of our operations.

At PET our commitment to excellence is achieved through consistent and integrated processes between head office and the field. In addition to formal policies, procedures and training programs, we foster individual responsibility and support creativity through an open exchange of ideas with our field personnel. Continual improvements are followed by concrete action plans. Open communication, reinforced with bonus incentives and safety recognition awards for field staff, emphasizes operational improvements that are practical and effective. Our people understand that environmental stewardship and the highest standards of safety go hand in hand with sound business decisions.

Our EH&S programs are guided by a committee of the Board of Directors with the majority being non-management directors. This committee provides directives for safety and environmental policies to protect the environment, maintain the health and safety of our employees, service providers and the public, and ensure compliance with all applicable laws, regulations and standards.

PET incorporates continuous improvement into our business planning and operations. Our operations are aligned with industry best practices and we strive to meet or exceed all regulatory requirements. PET participates in many industry tracking and benchmarking initiatives, both mandatory and voluntary, including the National Pollutant Release Inventory, the Canadian Greenhouse Gas Challenge Registry, the Carbon Disclosure Project, the Canadian Association of Petroleum Producers Stewardship Benchmarking Initiative, federal and provincial greenhouse gas reporting initiatives. PET meets all reporting requirements as mandated by regulatory authorities. In the event of an emergency, formal response programs are designed to minimize environmental and safety impacts. Finally, internal audit of our management systems and operations provides for continuous improvement to all aspects of EH&S.

Business Conditions

Industry Competition

We participate in the petroleum and natural gas industry which is highly competitive at all levels. We compete with other companies and other energy trusts for all of our business inputs including land and mineral rights, exploitation and development prospects, access to commodity markets, transportation, property and corporate acquisitions, available capital and manpower and equipment. We endeavour to be competitive by maintaining a strong financial position and by utilizing current and new technologies to enhance exploitation, development and operational activities.

Cyclical and Seasonal Impact

Our operational results and financial condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors including weather and general economic conditions as well as conditions in other oil and natural gas producing and consuming regions. Any decline in natural gas prices could have a material adverse effect on our financial condition.

Changes to Contracts

As of the date of this annual information form we do not anticipate that any aspect of our business will be materially affected in the current fiscal year by the renegotiation or termination of contracts or subcontracts.

Employees

As of December 31, 2006 the Administrator had 177 full and part-time permanent employees for the purposes of operating POT's natural gas operations and rendering administrative services to PET.

Social Citizenship

Through our In Stride with Community program, we direct funds to organizations that reflect PET's values and those of our employees and business partners. At PET our philosophy of investing in communities reflects our belief that setting high expectations creates a benchmark for achieving excellence. Our In Stride with Community funding emphasizes support for programs linked to academic study, wellness or life-shaping education. As we see it, education is a tool for achieving success, fulfilling dreams and learning lessons to make a difference in life. That education comes in many forms. PET can be found sponsoring scholastic programs, hockey teams, or promoting energy industry-related education in the communities in which we work. Our accomplishments rely on the support of our employees, consultants, service providers, business partners and our Unitholders. Their life priorities channel our sponsorship. Our people are actively improving the quality of life for friends and neighbours in their communities. To support those efforts, In Stride with Community dollars are directed to organizations where the people working with us are making a difference in the lives of others. We believe their enthusiasm and passion impacts our success, and when we contribute to enhance the impact of that energy in the community, great triumphs are attained.

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations under provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of requirements can result in suspension or revocation of necessary licenses and authorizations, civil liability for environmental damage and the imposition of material fines and penalties. This can have a significant negative impact on earnings and overall competitiveness.

We are proactive in our approach to environmental concerns. Procedures are in place to ensure that due care is taken in the day-to-day management of our natural gas properties. We believe that we are in material compliance with applicable environmental legislation. We pursue well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower our overall costs.

REGULATORY RULINGS – GAS OVER BITUMEN

The Alberta Energy and Utilities Board ("**AEUB**") issued General Bulletin 2003-28 ("**GB 2003-28**") and Shut-in Order 03-001 on July 22, 2003, establishing a process to identify gas production in the Wabiskaw-McMurray formations which may be posing an unacceptable risk to the potential bitumen resource. The AEUB considers that gas production in pressure communication with associated potentially recoverable bitumen places future bitumen recovery at an unacceptable risk.

Following the completion of a Regional Geological Study by the AEUB and an interim hearing held in March 2004 the AEUB ordered the shut-in, effective July 1, 2004, of Wabiskaw-McMurray natural gas production in northeast Alberta totalling approximately 123 MMcf/d. As of July 1, 2004, we had shut-in wells producing approximately 17.2 MMcf/d pursuant to Decision 2004-045 and Interim Shut-in Orders 04-001 and 04-002 including 4.5 MMcf/d from the zones shut-in on September 1, 2003 pursuant to the GB 2003-28 and Interim Shut-in Order 03-001. An additional 0.2 MMcf/d was shut-in September 1, 2004 pursuant to Decision 2004-064 and Interim Shut-in Order 04-003 related to wells in the Chard and Leismer areas.

On October 4, 2004 the Government of Alberta enacted amendments to the royalty regulation ("**Royalty Regulation**") with respect to natural gas. The amendments provide a mechanism whereby the government may prescribe additional royalty components to effect a reduction in the royalty calculated through the Crown royalty system for operators of gas wells which have been denied the right to produce by the AEUB as a result of recent bitumen conservation decisions. The Department of Energy issued Information Letter 2004-36 ("IL 2004-36") which, in conjunction with the Royalty Regulation, sets out the details of the gas over bitumen financial solution. In July 2005, further amendments to the Royalty Regulation were enacted with respect to natural gas, implementing a positive correction to the royalty calculation formula to provide a $0.05 per Mcf reduction in the effective operating costs adjustment. This effectively increases the net royalty adjustment by $0.025 per Mcf of deemed production and is retroactive to the date of shut-in. The revised formula for calculation of the royalty reduction provided in the Royalty Regulation is:

0.5 x ((deemed production volume x 0.80) x (Alberta Gas Reference Price - $0.3791/GJ))

Through this formula, operating costs are effectively deemed to be $0.40 Per Mcf, royalties are deemed to be 20%, the deemed production is assigned the Alberta Gas Reference Price, which includes a transportation component and the entire formula is assigned an arbitrary 50% reduction factor.

The Trust's net deemed production volume for purposes of the royalty adjustment was 20.8 MMcf/d in 2006. Deemed production represents all PET natural gas production shut-in or denied production pursuant to a Decision Report, corresponding AEUB Order or General Bulletin, or through correspondence in relation to an AEUB ID 99-1 application. In accordance with IL 2004-36, the deemed production volume related to wells shut-in is reduced by 10 percent at the end of every year of shut-in. PET's current deemed production is approximately 19.8 MMcf/d.

The majority of royalty adjustments received have been recorded on PET's balance sheet rather than reported as income as the Trust cannot determine if, when or to what extent the royalty adjustments may be repayable through incremental royalties if and when gas production recommences. Royalty adjustments may be repayable to the Crown in the form of an overriding royalty on gas production from wells which resume production within the gas over bitumen area. However, all royalty adjustments are recorded as a component of cash flow and as such are considered distributable income.

In the second quarter of 2006, PET disposed of certain shut-in gas wells in the gas over bitumen area. As part of the disposition agreement, the Trust continues to receive the gas over bitumen royalty adjustments related to the sold wells, although the ownership of the natural gas reserves is transferred to the buyer. As such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer PET's responsibility. As a result of this disposition, the gas over bitumen royalty adjustments received by the Trust for the affected wells are now considered revenue since they will not be repaid to the Crown. The Trust reclassified $13.7 million from the gas over bitumen liability on the balance sheet into revenues representing all royalty adjustments received to date in respect of the disposed wells.

During 2006, the Trust received $17.2 million in gas over bitumen royalty adjustments, of which $3.6 million was classified as revenue and $13.6 million was recorded on the Trust's balance sheet, as compared to $30.6 million received in 2004. The decrease is primarily due to lower gas prices as the royalty adjustment is calculated using the actual Alberta Gas Reference Price each month. The deemed production volume has also been reduced in 2006 as compared to 2005 in accordance with the Royalty Regulation. This brings cumulative royalty adjustments received to December 31, 2006 to $59.0 million.

Lease rental remission will also be granted for a mineral license or lease issued by the Crown that has a well or wells shut-in, according to IL 2004-036.

The phase 3 final hearing of GB 2003-28 was held between June 14, 2005 and August 12, 2005. We actively participated in the hearing, filing detailed evidence supporting the resumption of production from six gas pools representing approximately 8.5 MMcf/d of production which was shut-in pursuant to AEUB orders. We also reiterated to the AEUB our continued objection to all zones that had been shut-in as a result of the interim hearing based on the new evidence that we submitted.

On November 10, 2005 the AEUB issued Decision 2005-122 (the "**Final Decision**") regarding the phase 3 final hearing. The Final Decision had minimal impact on the Trust confirming the continued shut-in of the vast majority of the previously shut-in production. The Final Decision identified one additional well, producing less than 50 Mcf/d net to PET, for shut-in effective January 1, 2006. Shut-in PET wells with a productive capacity of less than 200 Mcf/d net to PET were approved for production for a net gain to our production of approximately 150 Mcf/d as a result of the Final Decision.

On January 24, 2006, the AEUB invited members in industry to a meeting to discuss its intent to commence a process with respect to bitumen conservation policies in the Cold Lake and Peace River Oil Sands Areas of Alberta. Industry comment was solicited prior to February 14, 2006 however the AEUB has not announced if or how it will proceed with respect to this matter. PET has current production of approximately 5.0 MMcf/d from the Bluesky-Gething formations in the portion of the Panny field and the Darwin field which are located within the Peace River Oil Sands Area. Gas production from a portion or all of these zones may be identified in the future as posing a potential concern with respect to communication with potentially recoverable bitumen resources. This production represents less than 5% of PET's current production. The Government of Alberta has not made comment as to whether the Gas over Bitumen Royalty Adjustment applied to shut-in gas in the Wabiskaw-McMurray in the Athabasca Oils Sands Area would apply to these other regions. There has been no expression of concern from bitumen resource owners in the Panny or Darwin areas.

On February 20th, 2007, the AEUB commenced a hearing to address industry participants' request to shut-in a number of Clearwater natural gas wells within the Cold Lake Oil Sands Area. PET has no Clearwater production within the Cold Lake Oil Sands area that would be affected by any decisions from the current hearing. The Peace River Oil Sands Area in not part of the current AEUB hearing.

PET continues to focus on converting its shut-in natural gas reserves back into producing assets. While the Trust is receiving partial relief for its lost cash flow in the form of monthly royalty reductions, PET still owns the shut-in reserves and they are more valuable if returned to production. PET continues to monitor new information as there is potential that future field evidence from actual SAGD projects will provide support to PET's technical position. The Trust also continues its active involvement in technical solution initiatives.

PET recently made application to initiate a technical solution pilot project in the Corner area. PET is proposing to inject and withdraw natural gas in a cyclical fashion in order to establish whether methane injection can restore pressure to depleted gas reservoirs, and at the same time evaluate the potential of the shut-in McMurray gas pools as gas storage reservoirs.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION IN ACCORDANCE WITH FORM 51-101F1

All of our reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan. More than 99 percent of our reserves are conventional natural gas.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the two Reports on Reserves Data (the "**McDaniel Reports**") by McDaniel & Associates Ltd. ("**McDaniel**") in Form 51-101F2 are attached as Appendices "**B**", "**C**" and "**D**" respectively to this annual information form.

Disclosure of Reserves Data

McDaniel performed evaluations of 100% of the Trust's properties, the results of which are included in the McDaniel Reports, dated January 30, 2007. The effective date of the McDaniel Reports is December 31, 2006. The McDaniel Reports summarize the natural gas reserves and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs of:

1) Paramount Energy Trust; and
2) Severo Energy Corp.

The reserves data set forth below (the "**Reserves Data**") is based upon the summation of the McDaniel Reports**.** Our oil and natural gas liquids reserves are immaterial. The Reserves Data conforms with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"). We engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The Reserves Data includes the estimated future net revenue (before deduction of income taxes) attributed to the Government of Alberta royalty adjustments for our reserves which have been shut-in as a result of the gas over bitumen issue as per the amendments to the Royalty Regulation. The Reserves Data also includes the estimated future net revenue (before deduction of income taxes) attributed to the reserves which have been shut-in or denied production as a result of the gas over bitumen issue if they were to recommence production. These reserves have all been classified as probable reserves and for the purposes of this additional valuation, McDaniel has assumed that these reserves will recommence production in the year 2014 or 2015 and will be subject to an additional 10% gross overriding royalty payable to the Crown. See **REGULATORY RULINGS – GAS OVER BITUMEN, RISK FACTORS** and **GOVERNMENT REGULATION**.

For income tax purposes we are able to and intend to claim deduction for all amounts paid or payable to the Unitholder and then allocate remaining taxable income, if any, to the Unitholders and therefore the Reserves Data has been presented on a before tax basis. If the October 31 Proposals are substantially enacted then the after tax values could be different than the pre-tax amounts presented. See **GENERAL DEVELOPMENT OF THE BUSINESS - *Income Tax Proposals.***

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. Actual natural gas reserves may be greater than or less than the estimates provided in this Reserves Statement.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE
TOTAL RESERVES
as of December 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORIES	NATURAL GAS		NET PRESENT VALUES OF FUTURE REVENUE AFTER COSTS BEFORE TAX DISCOUNTED AT (%/year) (1)				
	Gross MMcf	Net MMcf	0% ($M)	5% ($M)	10% ($M)	15% ($M)	20% ($M)
PROVED							
Developed Producing	161,349	131,388	666,344	591,781	533,683	487,490	450,009
Developed Non-Producing	7,023	5,701	(8,100)	(6,323)	(5,079)	(4,187)	(3,538)
Shut-in Gas over Bitumen Reserves (2)			(3,489)	(2,998)	(2,603)	(2,281)	(2,015)
Gas over Bitumen Royalty Adjustments			103,070	88,134	76,630	67,599	60,387
Undeveloped	6,703	4,899	6,738	4,569	2,785	1,331	149
TOTAL PROVED	175,075	141,988	764,563	675,162	605,416	549,952	504,992
PROBABLE							
Developed Producing, Developed Non-Producing and Undeveloped	62,128	50,154	275,360	213,443	171,484	141,837	120,082
Shut-in Gas over Bitumen Reserves	21,572	15,848	88,506	53,938	34,067	22,247	14,988
TOTAL PROBABLE	83,700	66,002	363,866	267,381	205,551	164,084	135,070
TOTAL PROVED PLUS PROBABLE	258,775	207,990	1,128,429	942,543	810,967	714,036	640,062

Notes:

(1) Net present values includes net revenue from oil, gas, and natural gas liquids.
(2) The negative values represent an estimate of the future abandonment costs of the gas over bitumen wells.

TOTAL FUTURE NET REVENUE
TOTAL RESERVES (UNDISCOUNTED)
as of December 31, 2006
FORECAST PRICES AND COSTS ($000's)

RESERVES CATEGORY	REVENUE	ROYALTIES	GAS OVER BITUMEN ROYALTY ADJUSTMENTS	OPERATING COSTS	DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE AFTER COSTS BEFORE INCOME TAXES
Proved Reserves	1,373,503	233,483	(103,070)	371,224	31,657	75,647	764,562
Proved Plus Probable Reserves	2,077,366	372,107	(103,070)	560,866	40,407	78,626	1,128,430

FUTURE NET REVENUE
TOTAL RESERVES
BY PRODUCTION TYPE
as of December 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE AFTER COSTS BEFORE INCOME TAXES (discounted at 10%/year) ($M)
Proved Reserves	Natural Gas (including by-products but excluding solution gas from oil wells)	605,415
Proved Plus Probable Reserves	Natural Gas (including by-products but excluding solution gas from oil wells)	810,967

Pricing Assumptions (Forecast Prices and Costs)

The forecast cost and price assumptions assume variations in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Natural gas benchmark reference pricing, as at December 31, 2006, inflation and exchange rates utilized by McDaniel in the McDaniel Report, which were McDaniel's then current forecasts at the date of the McDaniel Report, were as follows:

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2006
FORECAST PRICES AND COSTS

Forecast	AECO Spot Price Cdn$/GJ	Alberta Average Plantgate Cdn$/MMbtu	Aggregator Plantgate Cdn$/MMbtu	Alberta Spot Sales Plantgate Cdn$/MMbtu	Sask. Prov. Gas Plantgate Cdn$/MMbtu	Inflation%(1)	US/CAD Exchange Rate U.S.$/Cdn$(2)
2007	6.85	7.00	7.00	7.00	7.20	2.0	0.87
2008	7.05	7.25	7.25	7.25	7.45	2.0	0.87
2009	7.40	7.60	7.60	7.60	7.80	2.0	0.87
2010	7.50	7.70	7.70	7.70	7.90	2.0	0.87
2011	7.70	7.90	7.90	7.90	8.10	2.0	0.87
2012	7.90	8.15	8.15	8.15	8.35	2.0	0.87
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2.0	0.87

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

The Trust realized a weighted average gas price for the year ended December 31, 2006 of $7.52/Mcf for natural gas. The weighted average AECO daily gas price for the same 12 month period was $6.53/Mcf.

Reserves Data – (Constant Prices and Costs)

SUMMARY OF GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE
TOTAL RESERVES
as of December 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	NATURAL GAS		NET PRESENT VALUES OF FUTURE NET REVENUE AFTER COSTS BEFORE TAX DISCOUNTED AT (%/year) (1)				
	Gross MMcf	Net MMcf	0% ($M)	5% ($M)	10% ($M)	15% ($M)	20% ($M)
PROVED							
Developed Producing	158,730	129,125	503,074	454,845	416,230	384,833	358,878
Developed Non-Producing	6,820	5,525	(14,893)	(12,232)	(10,300)	(8,859)	(7,763)
Shut-in gas over Bitumen Reserves (2)			(3,254)	(2,801)	(2,436)	(2,137)	(1,890)
Gas over Bitumen Royalty Adjustments			78,842	67,832	59,314	52,599	47,213
Undeveloped	2,001	1,574	2,375	1,831	1,389	1,029	733
TOTAL PROVED	167,551	136,224	566,145	509,475	464,197	427,465	397,171
PROBABLE							
Developed Producing, Developed Non-Producing and Undeveloped	66,540	53,218	182,824	143,447	115,974	96,093	81,220
Shut-in Gas over Bitumen Reserves	21,177	15,532	50,955	31,844	20,581	13,743	9,469
TOTAL PROBABLE	87,717	68,750	233,779	175,290	136,555	109,837	90,690
TOTAL PROVED PLUS PROBABLE	255,268	204,974	799,924	684,765	600,752	537,302	487,861

Notes:
(1) Net present values includes net revenue from oil, gas, and natural gas liquids.
(2) The negative values represent an estimate of the future abandonment costs of the gas over bitumen wells.

TOTAL FUTURE NET REVENUE
TOTAL RESERVES (UNDISCOUNTED)
as of December 31, 2006
CONSTANT PRICES AND COSTS ($000's)

RESERVES CATEGORY	REVENUE	ROYALTIES	GAS OVER BITUMEN ROYALTY ADJUSTMENTS	OPERATING COSTS	DEVELOPMENT COSTS	WELL ABANDONMENT COSTS	FUTURE NET REVENUE AFTER COSTS BEFORE INCOME TAXES
Proved	1,059,654	170,844	(78,842)	321,559	13,516	66,432	566,145
Proved Plus Probable	1,582,810	275,200	(78,842)	480,500	38,968	67,060	799,924

FUTURE NET REVENUE
TOTAL RESERVES
BY PRODUCTION TYPE
as of December 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE AFTER COSTS BEFORE INCOME TAXES (discounted at 10%/year) ($M)
Proved	Natural Gas (including by-products but excluding solution gas from oil wells)	464,197
Proved Plus Probable	Natural Gas (including by-products but excluding solution gas from oil wells)	600,752

Pricing Assumptions (Constant Prices and Costs)

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2006
CONSTANT PRICES AND COSTS

Year	AECO Spot Price Cdn$/GJ	Alberta Spot Sales Plantgate Cdn$/MMbtu	Sask. Prov. Gas Plantgate Cdn$/MMbtu
December 31, 2006	5.81 (1)	5.93(1)	6.13

Notes:

(3) Constant Price is the price for daily natural gas spot sales on December 31, 2006 at AECO Hub, less adjustments for transportation and heating value.

Definitions and Other Notes

1. Columns and rows may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

   "**COGE Handbook**" means volumes 1 and 2 of the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

   "**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 reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) 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, pumping equipment and wellhead assembly;

(b) 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 wellhead assembly;

(c) 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

(d) provide improved recovery systems.

"**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 and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) 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;

(b) 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;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**Gross**" means:

(a) in relation to our interest in production and reserves, our "**Trust Gross Reserves**", which are our interest (operating and non-operating) share before deduction of royalties and without including any royalty interest;

(b) in relation to wells, the total number of wells in which we have an interest; and

(c) in relation to properties, the total area of properties in which we have an interest.

"**Net**" means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalties obligations, plus our royalty interest in production or reserves.

(b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

(c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

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

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

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

(i) **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 certainly.

(ii) **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.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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) to which they are assigned.

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:

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

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

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Reconciliations of Changes in Reserves and Future Net Revenue

RECONCILIATION OF TRUST GROSS RESERVES
TOTAL RESERVES (1)
FORECAST PRICES AND COSTS

FACTORS	Gross Proved (Bcf)	Gross Probable (Bcf)	Gross Proved Plus Probable (Bcf)
December 31,2005 (2)	195.8	86.8	282.6
Improved Recoveries, Extensions and Discoveries(3)	20.2	5.3	25.5
Technical Revisions	9.7	(6.0)	3.7
Acquisitions (net of dispositions)	5.4	(2.3)	3.1
Production	(56.0)	-	(56.0)
December 31, 2006	175.1	83.7	258.8

Notes:

(1) Includes reserves from zones not affected by gas over bitumen issue and reserves shut-in pursuant to AEUB decisions and orders described under the heading **REGULATORY RULINGS - GAS OVER BITUMEN.** See also **RISK FACTORS** and **GOVERNMENT REGULATION**.

(2) The opening balance on December 31, 2005 includes all of our reserves, including reserves that were shut-in or identified for shut-in as a result of the gas over bitumen issue. At December 31, 2005 and 2006 all reserves shut-in as a result of the gas over bitumen issue were categorized as probable reserves.

(3) The Trust includes all reserve additions resulting from capital expenditures in Extensions, Improved Recoveries and Discoveries.

RECONCILIATION OF TRUST NET RESERVES
TOTAL RESERVES (1)
FORECAST PRICES AND COSTS

FACTORS	Net Proved (Bcf)	Net Probable (Bcf)	Net Proved Plus Probable (Bcf)
December 31, 2005(2)	159.4	68.6	228.0
Improved Recoveries, Extensions and Discoveries(3)	16.4	4.1	20.5
Technical Revisions	7.4	(4.8)	2.6
Acquisitions (net of dispositions)	4.4	(1.9)	2.5
Production	(45.6)	-	(45.6)
December 31, 2006	142.0	66.0	208.0

Notes:

(4) Includes reserves from zones not affected by gas over bitumen issue and reserves shut-in pursuant to AEUB decisions and orders described under the heading **REGULATORY RULINGS - GAS OVER BITUMEN.** See also **RISK FACTORS** and **GOVERNMENT REGULATION**.

(5) The opening balance on December 31, 2005 includes all of our reserves, including reserves that were shut-in or identified for shut-in as a result of the gas over bitumen issue. At December 31, 2005 and 2006 all reserves shut-in as a result of the gas over bitumen issue were categorized as probable reserves.

(6) The Trust includes all reserve additions resulting from capital expenditures in Extensions, Improved Recoveries and Discoveries.

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
TOTAL RESERVES (1)
DISCOUNTED AT 10% PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	2006 ($000's)
Estimated Future Net Revenue at December 31, 2005 (1)	1,012,879
Sales of Gas Produced, Net of Production Costs and Royalties	(259,027)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(501,532)
Changes in Estimated Future Development Costs	14,304
Change Resulting From Improved Recovery, Extensions, and Discoveries	56,067
Acquisitions of Reserves	14,988
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	25,230
Accretion of Discount	101,288
Net Change in Income Taxes(2)	-
Estimated Future Net Revenue at December 31, 2006	464,197

Notes:

(1) The opening balance on December 31, 2005 includes all of our reserves, including reserves that were shut-in or identified for shut-in as a result of the gas over bitumen issue. At December 31, 2005 and 2006 all reserves shut-in as a result of the gas over bitumen issue were categorized as probable reserves.

(2) For income tax purposes we are able to and intend to claim deduction for all amounts paid or payable to the Unitholder and then allocate remaining taxable income, if any, to the Unitholders and therefore the Reserves Data has been presented on a before tax basis. If the October 31 Proposals are substantially enacted then the after tax values could be different than the pre-tax amounts presented. **See GENERAL DEVELOPMENT OF THE BUSINESS - *Income Tax Proposals* and RISK FACTORS.**

Additional Information Relating to Reserves Data

Undeveloped Reserves

The McDaniel Report estimates that future capital costs of $40.4 million will be required over the life of PET's proved plus probable reserves for the drilling, completion, equipping and tie-in of up to 72 wells and recompletion of up to 57 wells included in our proved plus probable reserves. In addition to opportunities on our asset base recognized in the McDaniel Report, many of our current assets include incremental exploitation opportunities. We are pursuing the drilling of over 130 gross wells as part of our 2007 capital expenditure program. Further, we have 74 additional locations at a drill-ready stage for drilling in future years including:

- seven locations in the East Side areas;
- 17 locations in the Athabasca areas;
- 11 locations in the West Side areas; and
- 39 locations in the Southern areas, including 23 locations in east central Alberta

.

Additional drilling prospects are at varying levels of technical analysis and economic evaluation. In addition, potential exists for incremental gas production through recompletion of uphole zones in existing wells and optimization of facilities. Over 129 workovers and secondary zone completions are budgeted for 2007. As our technical staff continue to analyze and evaluate the asset base and expand the facilities and pipeline infrastructure, additional opportunities are identified, enhancing the Trust's prospect inventory.

Additional exploitation, development and low exposure exploration opportunities, which we believe to be relatively low risk, will be pursued beyond 2007 at the discretion of the Administrator as economic factors such as commodity prices, operating costs and gas production rates change, whether due to market conditions or through the optimization of operations by the Administrator. The spending of additional capital beyond the estimates contained in the McDaniel Report would be intended to increase value to Unitholders through the addition of new reserves and acceleration of production in existing pools to decrease gas production rate declines with a corresponding increase in recoverable reserves, and a reduction in the number of years fixed costs are incurred. Facility optimization projects target production and reserves additions through improved recovery and by reducing operating costs to extend the economic life of producing assets with a corresponding increase in recoverable reserves.

Significant Factors or Uncertainties

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 reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

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 following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

	Future Development Costs Forecast Prices and Costs				Future Development Costs Constant Prices and Costs	
Year	**Proved Reserves**		**Proved Plus Probable Reserves**		**Proved Reserves**	
	0%	**10%**	**0%**	**10%**	**0%**	**10%**
2007	8,900	8,476	14,961	14,249	8,251	7,858
2008	22,278	19,288	22,584	20,438	4,838	4,378
2009	162	128	1,174	1,007	152	130
2010	70	50	546	443	65	53
2011	22	14	67	51	20	15
Thereafter	224	132	1,075	776	190	137
Total	31,656	28,089	40,407	36,964	13,516	12,572

We expect to fund future development costs from internally-generated cash flow, debt or equity financing through the capital markets or PET's Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan"), and we do not expect such costs to make development of any properties uneconomic.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of our oil and natural gas properties as at December 31, 2006. Production stated is our working interest share of production volumes and, unless otherwise stated, is average production for 2006. Reserve amounts stated include Trust Gross Reserves plus royalty interest reserves as at December 31, 2006 based on forecast costs and prices as evaluated in the McDaniel Report. See **Disclosure of Reserves Data**. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation. Unless otherwise specified, gross acres, net acres and well count information are as at December 31, 2006.

Northeast Alberta East Side

Chard/Kettle/Quigley

The Chard/Kettle/Quigley area is in northeast Alberta approximately 80 kilometres south of Fort McMurray. The area comprises 129,926 gross acres (120,494 net acres) including an average 91.8% working interest in 61 (56 net) producing natural gas wells. The average daily production for 2006 from the Chard area, including Kettle and Quigley, was approximately 6.5 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.98 Bcf and probable reserves at 2.04 Bcf of natural gas for the Chard/Kettle/Quigley area. In addition, we have 0.9 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. A majority of the production from the area is processed through a 100% PET owned gas plant at Kettle River. Two booster compressors reduce gathering system pressures to optimize production. Approximately 0.55 MMcf/d of gas flows through a third party plant in which PET has a 33.3% working interest.

Cold Lake

The Cold Lake area is in northeast Alberta approximately 250 kilometres southeast of Fort McMurray. The Cold Lake area comprises 128,999 gross acres (99,572 net acres) including an average 76.9% working interest in 78 (60 net) producing natural gas wells. The average daily production for 2006 from the Cold Lake Area was approximately 4.4 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.8 Bcf and probable reserves at 1.1 Bcf of natural gas for the Cold Lake area. Production from the Cold Lake area is processed through 14 booster and/or compressor stations owned by Altagas Services Inc. and four 100% PET owned compressor stations.

Corner/Leismer

The Corner/Leismer area is in northeast Alberta approximately 90 kilometres southwest of Fort McMurray. The area comprises 317,440 gross acres (302,074 net acres) including a 92.8% working interest in 69 (64 net) producing natural gas wells. The average daily production for 2006 from the Corner/Leismer area was approximately 6.4 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.6 Bcf and probable reserves at 1.7 Bcf of natural gas for the Corner/Leismer area. In addition, we have 16.9 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the Corner/Leismer area is processed through three 100% PET owned field booster compressors and one gas plant 32.5% owned by PET.

Craigend

The Craigend area is in northeast Alberta approximately 120 miles northeast of Edmonton. The Craigend area comprises 77,516 gross acres (56,983 net acres) with an average 77.1% working interest in 35 (27 net) producing natural gas wells. The average daily production for 2006 from the Craigend area was approximately 2.4 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 2.2 Bcf and probable reserves at 0.7 for the Craigend area. Production from the Craigend area is processed through a third-party gas plant.

Thornbury

The Thornbury area is in northeast Alberta approximately 75 kilometres southwest of Fort McMurray. The area comprises 58,240 gross acres (42,891 net acres) including an average 72.5% working interest in 40 (29 net) producing natural gas wells. The average daily production for 2006 from the Thornbury Area was approximately 3.6 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.2 Bcf and probable reserves at 1.5 Bcf of natural gas for the Thornbury area. In addition, we have 0.1 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the Thornbury area is processed through four gas plants and a field booster compressor owned by Altagas Services Inc.

<u>Northeast Alberta West Side</u>

Ells

The Ells area is located in northeast Alberta approximately 70 kilometres northwest of Fort McMurray. We own an undivided 100% working interest in 28,800 gross acres (25,120 net acres) as well as a 100% working interest in 21 producing natural gas wells. The average daily production for 2006 from the Ells area was approximately 3.7 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 2.5 Bcf and probable reserves at 0.9 Bcf of natural gas for the Ells Property. The Ells area includes related facilities including a 100% PET owned and operated gas plant and a booster compressor station.

Legend/East Legend

The Legend area, including East Legend, is approximately 110 kilometres northwest of Fort McMurray. The area comprises 302,720 gross acres (228,070 net acres) including an average 82.2% working interest in 90 (74 net) producing natural gas wells. The average daily production for 2006 from the Legend area was approximately 14.0 MMcf/d of natural gas. The McDaniel Report evaluated our proved reserves at 20.7 Bcf and probable reserves at 5.9 Bcf of natural gas for the Legend area. We have a 82.25% interest in an operated gas plant and nine field booster compressors, with working interests ranging from 78.8% to 100%, that process the natural gas from this area.

Liege

The Liege area is in northeast Alberta approximately 120 kilometres west of Fort McMurray. The area comprises 270,471 gross acres (238,713 net acres) including an average 94.2% working interest in 52 (49 net) producing natural gas wells. The average daily production for 2006 from the Liege Area, including South, North and East Liege, was approximately 6.0 MMcf/d of natural gas. The McDaniel Report evaluated PET's total proved reserves at 6.2 Bcf and probable reserves at 2.4 Bcf of natural gas for the Liege area. Production from the Liege area is processed through the South Liege gas plant owned 80.5% by PET and one East Liege field booster compressor owned 90.86% by PET. The North Liege production flows through a 100% PET owned booster compressor to a third party plant for processing.

Saleski

The Saleski area is in northeast Alberta approximately 110 kilometres west of Fort McMurray. The area comprises 140,480 gross acres (121,261 net acres) including an average 87.1% working interest in 31 (27 net) producing natural gas wells. The average daily production for 2006 from the Saleski area was approximately 5.8 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 14.2 Bcf and probable reserves at 3.9 Bcf of natural gas for the Saleski area. As a result of facility consolidation in the first quarter of 2005, production at Saleski is now processed through one gas plant owned 58.6% by PET.

Teepee Creek

The Teepee Creek area is in northeast Alberta approximately 175 kilometres west of Fort McMurray. The area comprises 32,640 gross acres (26,080 net acres) including an average 57.1% working interest in 14 (8 net) producing natural gas wells. The average daily production for 2006 from the Teepee Creek area was 1.8 MMcf/d. The McDaniel Report evaluated our total proved reserves at 1.7 Bcf and probable reserves at 0.5 Bcf of natural gas for the Teepee Creek area. Production from the Teepee Creek area is processed through a 100% PET owned and operated gas plant.

Woodenhouse

The Woodenhouse area is located in northeast Alberta approximately 140 kilometres southwest of Fort McMurray and 300 kilometres north of Edmonton and comprises 147,840 gross acres (146,951 net acres) with an average 100% working interest in 52 (52 net) producing natural gas wells. The property was acquired May 17, 2005. The average daily production for 2006 from the Woodenhouse area was 10.7 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 10.9 Bcf and probable reserves at 5.5 Bcf for the Woodenhouse area. Current production in Woodenhouse is processed through a 100% PET owned and operated gas plant.

<u>Athabasca</u>

Calling Lake

The Calling Lake area is located in northeast Alberta approximately 230 kilometres north of Edmonton and comprises 177,790 gross acres (100,231 net acres) with an average 54.17% working interest in 83 (45 net) producing natural gas wells. The average daily production for 2006 from the Calling Lake area was 9.2 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 8.2 Bcf and probable reserves at 3.2 Bcf for the Calling Lake area. Current production in Calling Lake is processed through a combination of operated and third party facilities.

Marten Hills

The Marten Hills area is located in northeast Alberta approximately 220 kilometres north of Edmonton and comprises 149,686 gross acres (124,504 net acres) including an average 83.7% working interest in 49 (41 net) producing natural gas wells. The average daily production for 2006 from the Marten Hills area was 10.6 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 13.5 Bcf of natural gas and probable reserves at 4.0 Bcf of natural gas. Production in the Marten Hills area is processed through a combination of third party and operated facilities.

Mistahae

The Mistahae area is located in northeast Alberta approximately 225 kilometres northwest of Edmonton and comprises 46,720 gross acres (46,720 net acres) with an average 100% working interest in 20 (20 net) producing natural gas wells. The average daily production for 2006 from the Mistahae area was 4.5 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.0 Bcf and probable reserves at 1.6 Bcf for the Mistahae area. Current production in Mistahae is processed through a 100% PET owned and operated facility.

Mitsue

The Mitsue area is located in northeast Alberta approximately 130 kilometres north of Edmonton and comprises 23,842 gross acres (14,739 net acres) including an average 68.4% working interest in 19 (13 net) producing oil and natural gas wells. The average daily production for 2006 from the Mitsue area was 4.5 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 2.5 Bcf of natural gas and probable reserves at 1.0 Bcf of natural gas for the Mitsue area. Production in the Mitsue area is processed through a 100% PET owned facility.

Panny

The Panny area is located in northeast Alberta and comprises 56,768 gross acres (55,120 net acres) with an average 100% working interest in 28 (28 net) producing natural gas wells. The average daily production for 2006 from the Panny area was 7.6

MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 8.2 Bcf and probable reserves at 3.2 Bcf for the Panny area. Current production in Panny is processed through a 100% PET owned gas processing facility.

Peter Lake

The Peter Lake area is located in northeast Alberta and comprises 51,814 gross acres (45,632 net acres) with an average 100% working interest in 16 (16 net) producing natural gas wells. The average daily production for 2006 from the Peter Lake area was 9.6 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 8.4 Bcf and probable reserves at 2.9 Bcf for the Peter Lake area. Currently a majority of the production in Peter Lake is processed through two 100% PET owned and operated gas processing facilities, while a small amount goes through a 100% PET owned booster compressor and is then processed through a third party facility.

Wabasca/Hoole

The Wabasca/Hoole area is located in northeast Alberta approximately 170 kilometres north of Edmonton. The area comprises 104,850 gross acres (100,127 net acres) with an average 96.8% working interest in 62 (60 net) producing natural gas wells. The average daily production for 2006 from the Wabasca/Hoole area was 16.9 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 20.3 Bcf and probable reserves at 6.4 Bcf for the Wabasca/Hoole area. Current production in Wabasca/Hoole is processed through a combination of 100% owned and operated compressor stations as well as third party facilities.

Southern

East Central Alberta

The east central Alberta area comprises assets in the Royal, Ukalta, Hairy Hill and Figure Lake fields acquired in February of 2006. The area includes 111,722 gross acres (105,996 net acres) including an average 95.5% working interest in 45 (43 net) producing natural gas wells. The average daily production for 2006 from the east central Alberta area was 6.8 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 6.0 Bcf of natural gas and probable reserves at 4.3 Bcf of natural gas. Production in the East Central Alberta area is processed through several third party facilities.

Southern Alberta

The Southern Alberta area comprises 132,917 gross acres (40,404 net acres) including an average 26.3% working interest in 99 (26 net) producing natural gas wells. The average daily production for 2006 from the Southern Alberta area was 2.2 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.5 Bcf of natural gas and probable reserves at 0.8 Bcf of natural gas. Production in the Southern Alberta area is processed through one owned booster compressor station and third party facilities.

Abbey, Saskatchewan

The Abbey area is in Southwest Saskatchewan and comprises 83,109 gross acres (83,109 net acres) including an average 100% working interest in 48 (48 net) producing natural gas wells. The average daily production for 2006 from the Abbey area was approximately 1.7 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 1.6 Bcf and probable reserves at 0.7 Bcf of natural gas for the Abbey area. Production from this area is processed through a facility 100% owned by PET.

West Central Saskatchewan

The West Central Saskatchewan area comprises 176,634 gross acres (142,848 net acres) including an average 96.3% working interest in 27 (26 net) producing natural gas wells. The average daily production for 2006 from the West Central Saskatchewan area was 1.0 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 0.5 Bcf and probable reserves at 0.4 Bcf. Production in West Central Saskatchewan is processed through a 100% owned facility and several third party facilities.

Severo Energy Corp.

Big Bend/Radway

In the third quarter PET completed an internal restructuring in order to facilitate the development of certain assets south of its Athabasca core area. Assets in the Big Bend and Radway areas producing approximately 1.4 MMcf/d were transferred to a private company, Severo Energy Corp. ("Severo"), which is 94% indirectly owned by PET. The Big Bend and Radway areas are located in northeast Alberta approximately 100 kilometres north of Edmonton and comprise 124,702 gross acres (56,890.9 net acres) with an average 21.1% working interest in 75 (19 net) producing natural gas wells. The property was acquired in September of 2006. The average daily production for 2006 from the Big Bend/Radway area was 2.0 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.5 Bcf and probable reserves at 1.6 Bcf for the Big Bend area. Current production in Big Bend/Radway is processed through a combination of operated and third party facilities.

Oil And Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2006.

	Natural Gas Wells			
	Producing		Non-Producing[3][4][5]	
Name of Area	**Gross[1]**	**Net[2]**	**Gross[1]**	**Net[2]**
Northeast Alberta East Side				
Chard/Kettle/Quigley	61	56	14	13
Cold Lake	78	60	1	1
Corner/Leismer	69	64	79	75
Craigend	35	27	1	1
Thornbury	40	29	7	4
East Side Other[6]	45	23	47	35
Subtotal:	328	259	149	128
Northeast Alberta West Side				
Ells	21	21	-	-
Legend	90	74	3	3
Liege	52	49	-	-
Saleski	31	27	-	-
Teepee Creek	14	8	-	-
Woodenhouse	52	52	-	-
West Side Other[7]	31	17	33	4
Subtotal:	291	248	36	7
Athabasca				
Calling Lake	83	45	-	-

	Natural Gas Wells			
	Producing		Non-Producing(3)(4)(5)	
Name of Area	Gross(1)	Net(2)	Gross(1)	Net(2)
Marten Hills	49	41	-	-
Mistahae	20	20	1	1
Mitsue	19	13	1	1
Panny	28	28	1	1
Peter Lake	16	16	1	1
Wabasca/Hoole	62	60	-	-
Athabasca Other	73	30	1	1
Subtotal:	350	253	5	5
Southern				
Southern Alberta	99	26	-	-
East Central Alberta	45	43	6	6
Abbey, Saskatchewan	48	48	-	-
West Central Saskatchewan	27	26	1	1
Southern Other	18	3		
	237	146	7	7
Severo Energy Corp.				
Big Bend/Radway	75	19	1	1
Subtotal:	75	19	1	1
TOTAL:	1,281	925	198	148

Notes:

(1) "**Gross**" refers to the number of wells, producing and non-producing, respectively, in which a working interest or royalty interest is held by PET.

(2) "**Net**" refers to the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest therein.

(3) "**Non-Producing**" refers to wells which are not currently producing either due to lack of facilities, markets or regulatory approval, but are capable of producing in commercial quantities. This includes 177 gross (128 net) wells shut-in as a result of gas over bitumen regulatory rulings)

(4) Allowance for the abandonment costs associated with the well bores was made in the McDaniel Report. There are 49 wells that are classified as service wells not included in the gross/net well count.

(5) Additionally, PET has 1,741 (1,165 net) wells which are not capable of producing in commercial quantities at this time.

(6) "**East Side Other**" includes Bohn Lake, Clyde, Pony Surmont, Winefred North and Winefred South.

(7) "**West Side Other**" includes Birch Tar, Hoole, Jean Lake and Portage and Fox Creek.

(8) "**Athabasca Other"** includes Darwin, Duncan and Ryan.

(9) **"Southern Other"** includes Bigoray, Cabin Creek, Highvale and Rosevar.

Acreage Information (Including for Properties with no Attributed Reserves)

The following table sets out our developed and undeveloped land holdings as at December 31, 2006.

	Developed Acres		Undeveloped Acres(3)(4)	
	Gross(1)	Net(2)	Gross(1)	Net(2)
Northeast Alberta East Side				
Chard	101,446	96,220.4	28,480	24,273.1
Cold Lake	94,939	71,176.4	34,060	28,396.0
Corner/Leismer	205,440	197,171.6	112,000	104,902.4
Craigend	45,600	30,355.2	31,916	26,628.1
Thornbury	48,000	34,187.8	10,240	8,704.0
East Side Other	144,960	73,349.2	43,200	32,741.3
	640,385	502,460.6	259,896	225,644.9
Northeast Alberta West Side				
Ells	11,520	10,560.0	17,280	14,560.0
Legend	186,240	147,785.6	116,480	80,284.7
Liege	174,720	156,372.9	95,751	82,339.6
Saleski	84,640	78,511.6	55,840	42,749.6
Teepee Creek	21,120	18,000.0	11,520	8,080.0
Woodenhouse	59,015	58,829.5	88,825	88,121.0
West Side Other	74,444	21,480.7	147,716	51,913.1
	611,699	491,540.3	533,411	368,048.0
Athabasca				
Calling Lake	100,000	50,251.1	77,790	49,980.3
Marten Hills	95,442	74,629.1	54,244	49,874.6
Mistahae	23,680	23,680.0	23,040	23,040.0
Mitsue	15,042	9,171.0	8,800	5,567.8
Panny	29,024	27,840.0	27,744	27,280.0
Peter Lake	23,715	20,309.6	28,099	25,322.6
Wabasca/Hoole	46,616	43,904.0	58,234	56,223.0
Athabasca other	132,800	39,818.7	137,280	93,364.5
	466,318	289,603.5	415,230	330,652.6
Southern				
Southern Alberta	71,024	21,808.9	61,893	18,595.7
East Central Alberta	37,274	34,427.8	74,448	71,568.5
Abbey, Saskatchewan	13,939	13,939.0	69,170	69,169.9
West Central Saskatchewan	42,408	37,514.4	134,226	105,333.2
	164,645	107,690.1	339,737	264,666.3
Severo Energy Corp.				
Big Bend/Radway	79,265	23,920.5	45,437	32,970.4
Total	1,962,311	1,415,215.0	1,593,711	1,221,982.2

Notes:

(1) "**Gross**" means the total number of developed and undeveloped acres, respectively, in which we have an interest in respect of our current assets.

(2) "**Net**" means the aggregate of the numbers obtained by multiplying each gross acre by the actual percentage interest therein.
(3) During 2006, 35,809 net acres are set to expire. We intend to assess such expiring lands and, where appropriate, seek continuation through development activity or, in the case of higher risk areas, farm outs, where third parties provide exploration funding in exchange for an earned working interest.
(4) "**Undeveloped Acres**" refers to land where no reserves have been assigned by McDaniel in the McDaniel Report.
(5) We do not have any material work commitments on any of our properties.

Marketing and Transportation

We proactively manage our gas portfolio in order to maximize the price we obtain for our production. With the volatility of gas markets, we are aggressive and opportunistic. Our dedicated team of gas marketing professionals is responsible for hands-on management of our physical gas sales and hedging, including transportation and storage arrangements. Continuous market surveillance and analysis leads us to employ various hedging tools and pricing arrangements to, among other things:

- Protect the level of monthly distributions;
- Enhance or protect the economics of an acquisition by capturing pricing either at the same level or higher than the original evaluation; and
- Capitalize on short-term anomalies in the market.

Aside from the physical forward sales contracts at AECO fixed prices outlined below, we currently have no material future contracts to buy, sell, exchange or transport natural gas from our assets. According to January estimates, we currently sell approximately 76.9% of our gas production at AECO-based market prices. The remaining 23.1% is directed to natural gas aggregator pools.

Total financial hedge arrangements and physical sales contracts outstanding as of March 5, 2007 are as follows:

Type of contract	PET transaction	Volumes at AECO (GJ/d)	Fixed Price ($/GJ)	Term
Financial	sold	62,500	$7.65	April – October 2007
Financial	bought	(7,500)	$7.09	April – October 2007
Physical	sold	35,000	$8.00	April – October 2007
Period total, net (1)	**sold**	**90,000**	**$7.79**	**April – October 2007**
Financial	sold	45,000	$9.09	November 2007 – March 2008
Physical	sold	37,500	$9.69	November 2007 – March 2008
Period total, net	**sold**	**82,500**	**$9.36**	**November 2007 – March 2008**
Financial	sold	25,000	$7.54	April – October 2008

(1) Weighted average prices are calculated using floor prices for collars, and netting the volumes of the financial sell/buy contracts together and measuring the net volume at the weighted average "sell" price for the financial contracts.

PET's NYMEX-based financial and physical forward gas sales arrangements as of February 23, 2007 are as follows:

Type of contract	PET transaction	Volumes at NYMEX (MMBTU/d)	Price (US$/MMBTU)	Term
Financial	sold	2,500	$10.30	November 2007 – March 2008
Financial	bought	(2,500)	$10.24	November 2007 – March 2008
Physical	sold	2,500	$10.29	November 2007 – March 2008
Physical	sold	5,000	$6.68	April – October 2008
Financial	sold	10,000	$7.70	April – October 2008

Foreign exchange price hedges

PET has entered into financial contracts to sell forward Canadian dollars for US dollars at a fixed exchange rate in order to mitigate the effect of exchange rate fluctuations on the Trust's realized natural gas price. Foreign exchange contracts outstanding as at December 31, 2006 are as follows:

Type of Contract	CDN$ sold (monthly)	Fixed FX rate (CDN$/US$)	Term
Financial	$1,000,000	1.1100	April – October 2008

Additional Information Concerning Abandonment and Reclamation Costs

We engaged Prevent Technologies Ltd. ("Prevent"), an independent evaluator, to estimate our total future asset retirement obligation based on our net ownership interest in all wells and facilities, including wells with no reserves attributed, estimated costs to abandon the wells and facilities and reclaim the sites and the estimated timing of the costs to be incurred in future periods. Pursuant to this evaluation, we have estimated the net present value of our total asset retirement obligations to be $109.4 million as at December 31, 2006 based on an undiscounted total future liability of $213.7 million. As at December 31, 2006, the estimated undiscounted net salvage value of our gas plants, compressors and facilities was estimated at $102.5 million ($51.9 million discounted at 10%). The McDaniel Report includes an undiscounted amount of $78.6 million ($39.0 million discounted at 10%) with respect to expected future well abandonment costs related specifically to our proved and probable reserves.

Tax Horizon

PET, and its principal operating entity POT, are taxable entities to the *Income Tax Act* (Canada) and are taxable only on income that is not distributed or distributable to the Unitholders. As the Trust distributes all of its taxable income to the Unitholders pursuant to the Trust Indenture and meets the requirements of the *Income Tax Act* (Canada) applicable to the Trust no income taxes are expected to be paid in the foreseeable future. See **GENERAL DEVELOPMENT OF BUSINESS – Income Tax Proposals**.

Capital Expenditures

The following tables summarize capital expenditures related to our activities for the year ended December 31, 2006:

Proved property acquisition costs (net)	79,760
Unproved property acquisition costs	12,621
Exploration costs	13,758
Development Costs	111,880
Total	**$218,019**

Exploration and development expenditures for 2006 include approximately $13.8 million in exploration costs which have been expensed directly on the Trust's statement of earnings. PET follows the Successful Efforts accounting methodology, thus exploration costs include seismic expenditures, dry hole costs and expired leases and are considered to be more closely related to investing activities than operating activities. As a result they are included with capital expenditures.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2006:

	Gross	**Net**
Light and Medium Oil	0	0.0
Natural Gas	148	111.8
Service	0	0.0
Dry	4	1.9
Total	152	113.7
Success Rate (%)	97	98
Exploratory	40	32.7
Development	112	81
Total	152	113.7

Production Estimates

The following table sets out the volume of our production estimated by McDaniel on a proved and probable basis for the year ended December 31, 2007, which is reflected in the estimate of future net revenue disclosed in the tables contained under **STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION IN ACCORDANCE WITH FORM 51-101F1.**

2007	**Natural Gas (MMcf/d)**
Proved	133.1
Probable	12.1
Total Proved plus Probable	145.2

Production History

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

	2006 Quarter Ended			
	Dec 31	**Sept 30**	**June 30**	**Mar 31**
Average Daily Production Volume				
Natural Gas (MMcf/d)	144.6	154.6	162.9	151.5
Average Prices Received ($/Mcf)	$7.83	$7.36	$6.85	$8.09
Royalties Paid ($/Mcf)	(1.00)	(1.04)	(1.09)	(1.61)
Operating Costs ($/Mcf)	(1.65)	(1.39)	(1.31)	(1.67)
Transportation Costs ($/Mcf)	(0.18)	(0.21)	(0.20)	(0.25)
Resulting Netback ($/Mcf)	$5.00	$4.72	$4.25	$4.56

The following table indicates our average daily production from each of PET's core areas for the year ended December 31, 2006:

Name of Area	**Production (MMcf/d)**
Northeast Alberta East Side	
Chard	6.4
Cold Lake	4.4
Corner/Leismer	6.4
Craigend	2.4
Thornbury	3.6
East Side Other	3.2
	26.4
Northeast Alberta West Side	
Ells	3.7
Legend	14.0
Liege	6.2
Saleski	5.8
Teepee Creek/Woodenhouse	12.0
West Side Other	4.6
	46.3
Athabasca	
Calling Lake	9.2
Athabasca Other	4.1
Marten Hills	10.6
Mistahae	4.5
Mitsue	4.5
Panny	7.6
Peter Lake	9.6
Wabasca/Hoole	16.9
	67.0
Southern	
East Central Alberta	6.8
Southern Alberta	2.2

Abbey	1.7
West Central Saskatchewan	1.0
	11.7
Severo	
Big Bend/Radway	2.0
	2.0
Total	**153.4**

RISK FACTORS

Consider the risks described below before making an investment decision. Refer to the other information included in PET's disclosure record on www.sedar.com including financial statements and related notes.

Uncertainty exists with respect to our ability to produce a portion of our natural gas reserves.

Recent decisions by the AEUB have brought into question our ability to continue to produce natural gas from all of the Wabiskaw and McMurray formations in certain parts of the Athabasca Oil Sands Area in Northeast Alberta. The AEUB has ordered shut-in of some of our production and reserves in this area.

On January 24, 2006, the AEUB invited members in industry to a meeting to discuss its intent to commence a process with respect to bitumen conservation policies in the Cold Lake and Peace River Oil Sands Areas of Alberta. Industry comment was solicited prior to February 14, 2006 however the AEUB has not yet announced if or how it will proceed with respect to this matter. PET has current production of approximately 5.8 MMcf/d from the Bluesky-Gething formations in the portion of the Panny field and the Darwin field which are located within the Peace River Oil Sands Area. Gas production from these zones may be identified in the future as posing a potential concern with respect to communication with potentially recoverable bitumen resources. This production represents less than 5% of PET's current production. The Government of Alberta has not made comment as to whether the Gas over Bitumen Royalty Adjustment applied to shut-in gas in the Wabiskaw-McMurray in the Athabasca Oils Sands Area would apply to these other regions. There has been no expression of concern from bitumen resource owners in the Panny or Darwin areas.

While we have no significant additional production recommended for shut-in by any party or the AEUB at this time and royalty adjustments are being received for production currently shut-in, we cannot ensure that additional production will not be shut-in in the future or that we will be able to negotiate adequate compensation for having to shut-in any such production. This could have a material adverse effect on the amount of income available for distribution to Unitholders. See **REGULATORY RULINGS – GAS OVER BITUMEN**.

Our reserves will be depleted over time. We may be unable to develop or acquire additional reserves.

Royalty trusts, structured as PET is, have certain unique attributes that differentiate them from other natural gas industry participants. The primary source of distributable income to Unitholders will be from our natural gas properties which, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. We will not be reinvesting cash flow in the same manner and to the same extent as traditional, non-trust industry participants. Accordingly, absent capital injections, our production levels and reserves will decline over time.

Our future natural gas reserves and production and, therefore, our cash flows will be highly dependent on our success in exploiting our reserve base and acquiring additional reserves especially given that as production declines in mature areas, such as those areas comprising our current assets, the unit production costs increase. Without reserve additions through acquisition or development activities, our reserves and production will decline over time as these reserves are exploited.

To the extent that external sources of capital, including the proceeds of any issuance of additional Trust Units, become limited or unavailable our ability to make the necessary capital investments to maintain or expand our natural gas reserves will be impaired. If we use production revenue to finance capital expenditures or property acquisitions the level of distributable income to Unitholders will be reduced.

Our reserves data regarding our current assets are estimates. Actual production, revenues and expenditures may differ from such estimates resulting in the actual net value of reserves being lower.

Estimates of our natural gas reserves depend in large part upon the reliability of available geological and engineering data. Geological and engineering data are used to determine the probability that a reservoir of natural gas exists at a particular location and whether, and the extent to which, natural gas is recoverable from a reservoir. The reliability of reserve estimates depends on:

- whether the prevailing tax rules and other government regulations will remain the same as on the date estimates are made;
- whether existing contracts remain the same as on the date estimates are made;
- whether natural gas and other prices will remain the same as on the date estimates are made;
- the production performance of our reservoirs;
- extensive engineering judgments;
- the price at which recovered natural gas can be sold;
- the costs associated with recovering natural gas;
- the prevailing environmental conditions associated with drilling and production sites;
- the availability of enhanced recovery techniques; and
- the ability to transport natural gas to markets.

Our title to our assets may have defects. This could result in additional costs and adversely affect our interests in disputed properties.

We have not obtained a legal opinion as to the title to our assets and cannot guarantee or certify that a defect in the chain of title may not arise to defeat our claim to a particular natural gas property. Remediation of title problems could result in additional costs and litigation. If we are not able to remedy these title defects, we may lose some of our interest in the disputed properties resulting in reduced production and distributable income available to Unitholders.

Our lenders have the ability, in certain circumstances, to impair our ability to pay distributions on Trust Units and to pay cash redemptions for Trust Units.

Under the terms of the credit facility with our lenders, if the lenders determine that our borrowing base under the facility has been exceeded by the amount loaned and assuming there is not a demand for repayment we will be precluded from providing distributions on Trust Units and from paying cash for redemptions of Trust Units until our borrowing base no longer is in a shortfall position. Our lenders may also restrict our ability to pay distributions when we are in breach or default of agreements with the lenders.

The lenders will be provided with security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default such as bankruptcy, the lender may foreclose on or sell the working interests.

The net asset value of our assets may differ from our trading price.

The net asset value of the our assets will vary from time to time dependent upon a number of factors beyond the control of management including oil and natural gas prices. The trading prices of the Trust Units from time to time are also determined by a number of factors that are beyond the control of management and such trading prices may be greater than the net asset value of our assets.

Our operations involve many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our operations may be delayed or unsuccessful for many reasons including cost overruns, lower natural gas prices, equipment shortages, mechanical and technical difficulties and labour problems. Our operations will also often require the use of new and advanced technologies which can be expensive to develop, purchase and implement and may not function as expected. We may experience substantial cost overruns caused by changes in the scope and magnitude of our operations, employee strikes and unforeseen technical problems including natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions giving rise to liability to third parties. In particular, drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. Drilling for natural gas could result in unprofitable efforts, not only from dry wells but from wells that are productive but do not produce enough net revenue to return a profit after drilling, operating and other costs. The costs of drilling, completing and operating wells are often uncertain. In addition, our operations depend on the availability of drilling and related equipment in the particular areas where exploration and development activities will be conducted. Demand for the equipment or access restrictions may affect the availability of that equipment and, consequently, delay operations.

Our operations may be impacted by cyclical and seasonal factors.

Our operational results and financial condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors including weather and general economic conditions as well as conditions in other oil and natural gas producing regions. Any decline in natural gas prices could have an adverse effect on our financial condition.

Our operations may expand into other jurisdictions.

Our operations and the expertise of our management are currently focused on conventional gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities of the Trust to oil and gas production and development, and the Trust 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 new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors, which may result in future operational and financial conditions of the Trust being adversely affected.

We may decide to participate in other business activities.

The Trust Indenture does not limit our activities to oil and gas production and development. We could acquire other energy related assets such as natural gas processing plants or pipelines, an interest in an oil sands project or participate in gas marketing commercial ventures. Expansion of our activities into new areas may present additional risks or, alternatively, significantly increase the exposure to one or more of the present risk factors. In either case, our future operational and financial conditions could be materially adversely affected.

We will encounter competition in all areas of our business and may not be able to successfully compete with our competitors.

The natural gas industry is extremely competitive, especially with regard to exploration for, exploitation of and development of new sources of natural gas. We may not be able to compete successfully with some of our larger, more established competitors. Consequently, we may be forced to pay more for attractive properties or may be unable to acquire new assets efficiently. These factors would materially adversely affect our ability to maintain and expand our natural gas reserves.

Some of our competitors are much larger, more established companies with substantially greater resources. In many instances they have been engaged in the natural gas business much longer than us. These larger companies, especially those created by recent mergers, are developing strong market power through a combination of different factors, including:

- diversification and reduction of risk;
- financial strength necessary for capital-intensive developments;
- exploitation of benefits of integration;
- exploitation of economies of scale in technology and organization;
- exploitation of mutual advantages of expertise, industrial infrastructure and reserves; and strengthening of positions as global players.

These companies may be able to pay more for productive natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects, including operatorships and licenses, than our financial or human resources permit. They may also be able to attract more qualified employees including key personnel currently employed by the Administrator.

The success of your investment is highly dependent on our key personnel.

You will be entirely dependent on management in respect of the administration of all matters relating to our assets and securities. If you are not willing to rely on management you should not invest in the Trust Units. Moreover, our operations will be highly dependent upon executive officers and key employees. The unexpected loss of the services of any of these individuals could have a detrimental effect on us.

Some of our key personnel may have conflicts of interest.

Some of the officers and directors of the Administrator are also directors of other natural gas companies that may, from time to time, be in competition with us for working interest partners, property acquisitions, key employees and other resources. This could result in the loss of attractive business opportunities or of talented personnel.

The production and revenue of our properties may, to some extent, be dependent on the ability of third party operators.

The continuing production from less than 10% of our current assets based on current production and, to some extent, the marketing of such production, are dependent upon the ability of third party operators of the property. If, in situations where we are not the operator, the operator fails to perform these functions properly or becomes insolvent our revenue may be reduced. Payments from production flow through the operator and, where we are not the operator, there is a risk of delay and additional expenses in receiving such revenues. As owner of working interests in properties we do not operate, we will generally have only a cause of action for damages arising as a result of the gross negligence or wilful misconduct of the operator. The expense of bringing such an action could be significant and we may be unsuccessful in recovering damages. Additionally, any delay in payment along the production chain could adversely impact our distributions to Unitholders.

We are not insured against all potential losses and could be seriously harmed by natural disasters or operational catastrophes.

Exploration for natural gas and the production of natural gas are hazardous undertakings. Further, natural disasters, operator error or other occurrences can result in oil spills, blowouts, cratering, fires, equipment failure and loss of well control, which can injure or kill people, damage or destroy wells and production facilities and damage other property and the environment. Losses and liabilities arising from such events could significantly reduce our revenues or increase costs and have a material adverse effect on our operations or financial condition.

We may be unable to obtain insurance against these risks at premium levels that justify its purchase. Further, insurance may be unavailable or any insurance we may obtain may be insufficient to provide full coverage. The occurrence of a significant event that is not fully insured could have a material adverse effect on our financial position and reduce or eliminate distributions to Unitholders.

We may be unable to secure additional financing.

Our primary source of bank financing is a demand credit facility with a syndicate of Canadian chartered banks in the amount of $310 million. The credit facility is presently due March 31, 2006. We expect that the facility will be extended at that date. If the facility is not extended we will need to find alternative sources of financing. If alternative sources of financing are not available, or are more expensive than the current credit facility, we may be unable to effectively operate our business or pay distributions to Unitholders.

In the normal course of making capital investments to maintain and expand our reserves, additional Trust Units may be issued from treasury which may result in a decline in production per Trust Unit and reserves per Trust Unit. Additionally, from time to time we may issue Trust Units from treasury in order to reduce debt and maintain a more optimal capital structure. Conversely, to the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our reserves will be impaired. To the extent that we are required to use cash flow to finance capital expenditures or property acquisitions, to pay debt services charges or to reduce debt, the level or distributable income will be reduced.

Trust Units will have very limited value when reserves from our properties can no longer be economically produced. We will need to seek additional financing to maintain and expand our business. Such financing may not be available on terms or under conditions that are favourable to us or at all.

Significant capital expenditures could reduce or even eliminate distributions to Unitholders.

The timing and amount of capital expenditures will directly affect distributions. We may reduce or even eliminate distributions at times when it makes significant capital or other expenditures.

It may be difficult for you to dispose of Trust Units or recoup your investment.

The right to redeem Trust Units will not be the primary mechanism for Unitholders to liquidate their investments. Further, there may not be an active trading market for the Trust Units that would facilitate other sales. Generally, we will not redeem in cash more than $100,000 of Trust Units in any one calendar month. Instead we will pay such excess redemption amount by the issuance of promissory notes of PET which will be unsecured, subordinated to all of our indebtedness and due and payable five years after issuance. No market is expected to develop for the promissory notes. Our ability to pay redemptions in cash or to make payment on promissory notes may be further restricted by our lenders.

A return on an investment in the Trust is not comparable to the return on an investment in a fixed-income security. The recovery of an initial investment in the Trust is at risk, and the anticipated return on such investment is based on many performance assumptions. Although we intend to make distributions of its available cash to holders of Trust Units, these cash distributions may be reduced or suspended. The actual amount distributed will depend on numerous factors including: our financial performance and the financial performance of POT, debt obligations, working capital requirements and future capital requirements. In addition, the market value of the Trust Units may decline if the Trust's cash distributions decline in the future, and that market value decline may be material.

It is important for an investor to consider the particular risk factors that may affect the industry in which it is investing, and therefore the stability of the distributions that it receives.

The after-tax return from an investment in Trust Units to Unitholders subject to Canadian income tax can be made up of both a return on capital and a return of capital. That composition may change over time, thus affecting an investor's after-tax return. Returns on capital are generally taxed as ordinary income in the hands of a Unitholder. Returns of capital are generally tax-deferred (and reduce the Unitholder's cost base in the Trust Unit for tax purposes).

You may suffer dilution of your interest.

To maintain or expand our natural gas reserves we will need to finance capital expenditures and property acquisitions. Consequently, you may suffer dilution as a result of any future offering of Trust Units or securities convertible into Trust Units.

Trust Units do not carry the same statutory rights as common shares.

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in either the Administrator or the Trust. Corporate law does not govern the Trust and the rights of Unitholders. Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada) and the *Companies' Creditors Arrangement Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation

Trust Units may expose you to personal liability.

Unitholders are not protected from our liabilities to the same extent that a shareholder would be protected from a corporation's liabilities. For example, personal liability of Unitholders may arise from claims in tort or claims for taxes against PET. Unlike many other royalty trusts and income funds, the Trust's structure does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to Unitholders. As a result, ownership of Trust Units may expose you to personal liability.

Note, however, that on July 1, 2004 the *Income Trust Liability Act* (Alberta) came into force creating a statutory limitation on the liability of unitholders of Alberta income trusts such as the Trust. The legislation provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee. The implementation of the *Income Trust Liability Act* (Alberta) assists in mitigating the effect of the Trust's structure and its lack of an inter-positioned limited liability entity. This legislation has not been subject to interpretation by the courts in the Province of Alberta.

Non-Residents are subject to restrictions on their ownership of our securities, which may require them to sell their Trust Units when market conditions are not favourable.

The Trust Indenture restricts the ownership of Trust Units by Unitholders who are non-residents of Canada for the purposes of the *Income Tax Act* (Canada). Unitholders who are non-residents of Canada face the risk of being forced to sell some or all of their Trust Units in order to comply with these restrictions.

The application of generally accepted accounting principles ("GAAP") may result in accounting write-downs

GAAP requires that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in our consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the Trust Unit price. The carrying value of property, plant and equipment, the carrying value of goodwill and the value of hedging instruments are some of the items which are subject to valuation and potential non-cash write-downs.

Any decline in the marketability or the price of natural gas could materially harm our financial condition.

The prices of natural gas and demand for natural gas fluctuate for reasons largely beyond our control. Such fluctuations may have a negative effect on our revenue (and consequently, on distributable income) as well as on the acquisition costs of any future natural gas properties that we may acquire. Our current production is weighted exclusively to natural gas and we may be more subject to price fluctuations in natural gas than our competitors whose production is more diversified.

Natural gas prices are extremely volatile. Oil prices are determined by international supply and demand. Political developments, compliance or non-compliance with self-imposed quotas, or agreements between members of the Organization of Petroleum Exporting Countries all can affect world oil supply and prices. Numerous other factors beyond our control will affect the marketability and price of natural gas that we acquire or discover, including:

- the demand for natural gas;
- the proximity and capacity of natural gas pipelines and processing equipment;
- changes in government regulations (including regulations relating to environmental protection, royalties, allowable production, pricing and importing and exporting of natural gas);
- weather;
- the price of other energy related commodities;
- general economic conditions; and
- conditions in other natural gas producing and consuming regions.

The negative impact of any one of these or other factors could have a material adverse affect on our results of operations, distributable income and overall financial condition.

Variations in interest rates may limit distributions to Unitholders.

Variations in interest rates could result in a significant increase in the amount we pay to service its debt resulting in a decrease in distributions to Unitholders.

Our loan agreements and credit facilities can affect distributions to Unitholders

Certain covenants in our loan agreements could limit distributions to Unitholders. Further, our credit facilities are subject to periodic review. Our lenders may reduce the size of the credit facilities limiting our ability to maintain operations and to acquire new properties. This would reduce distributions to Unitholders.

As a Canadian operator we are exposed to risk caused by fluctuations in currency exchange rates.

Our operating costs, including costs of production, are generally paid in Canadian dollars. World oil prices are quoted in U.S. dollars. The price Canadian producers receive is therefore affected by the Canadian/U.S. dollar exchange rate that will fluctuate over time. U.S. natural gas markets and prices have a significant effect on Canadian natural gas prices. A material increase in the value of the Canadian dollar may negatively impact our production revenue.

Future hedging activities could result in losses.

The nature of our operations results in exposure to fluctuations in commodity prices. We will monitor and, when appropriate, utilize derivative financial instruments and physical delivery contracts to hedge our exposure to these risks. We may be exposed to credit-related losses in the event of non-performance by counter-parties to the financial instruments. From time to time we may enter into hedging activities in an effort to mitigate the potential impact of declines in natural gas prices. These activities may consist of, but are not limited to:

- buying a price floor under which we will receive a minimum price for natural gas production;
- buying a collar under which we will receive a price within a specified price range for natural gas production;
- entering into fixed price contract for natural gas production;
- entering into contracts to fix the basis differential between natural gas markets; and
- entering into contracts to fix the price differential between light and heavy oil.

If product prices increase above the levels specified in our various hedging agreements, we would be precluded from receiving the full benefit of commodity price increases.

In addition, by entering into these hedging activities we may suffer financial loss if:

- we are unable to produce sufficient quantities of natural gas to fulfill our obligations;

- we are required to pay a margin call on a financial hedge contract; or

- we are required to pay royalties based on a market or reference price that is higher than our hedged fixed or ceiling price.

Changes in the market values of our permitted investments could adversely affect the value of the Trust Units.

We may invest in certain permitted investments of which the market value may fluctuate. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Other permitted investments in energy-related entities will be subject to the general risks of investing in equity securities. These include the risks that the financial condition of issuers may become impaired or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors including governmental, environmental and regulatory policies; inflation and interest rates; economic cycles; and global, regional and national events. The value of the Trust Units could be affected by adverse changes in the market values of permitted investments.

Changes in tax legislation could materially adversely affect our business.

The treatment of mutual fund trusts could be changed in a manner which adversely affects Unitholders. If we cease to qualify as a "mutual fund trust" under the *Income Tax Act* (Canada), the Trust Units will cease to be qualified investments for registered retirement savings plans, registered education savings plans, deferred profit sharing plans and registered retirement income funds.

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

The Administrator intends that we will continue to qualify as a mutual fund trust for purposes of the *Income Tax Act* (Canada). We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and our Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders including income generated by the royalties held by us. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders who are not residents of Canada and residents of Canada who are otherwise exempt from Canadian income tax.

- We would cease to be eligible for the capital gains refund mechanism available under Canadian tax legislation.

- Trust Units held by Unitholders who 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.

- Trust Units would not constitute qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs") or deferred profit sharing plans ("DPSPs"). If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to 1% of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units it may have its registration revoked by the Canada Revenue Agency.

The Administrator may take certain measures in the future to the extent it believes necessary to ensure that we maintain our status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the *Income Tax Act* (Canada).

Income Tax Proposals

The October 31 Proposals propose to apply a tax at the trust level on distributions of certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax at 31.5% and to treat such distributions as dividends to the Unitholders. Existing trusts will have a four-year transition period and, subject to the qualification below, the new tax proposals will apply in January 2011. Assuming the October 31 Proposals are ultimately enacted in the form currently proposed, the implementation of such proposals would be 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.

In light of the foregoing, the October 31 Proposals has reduced the value of the Trust's Units, which would be expected to increase the cost to PET of raising capital in the public capital markets for acquisition opportunities. In addition, the October 31 Proposals are expected to place PET and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. There can be no assurance that PET will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the October 31 Proposals.

Further, the proposal plan provides that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being "revisited", presumably with the loss of the benefit to the Trust of that transitional period. As a result, the adverse tax consequences resulting from the proposals could be realized sooner than 2011. On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by "normal growth" in this context. Specifically, the Department of Finance stated that "normal growth" would include equity growth within certain "safe harbour" limits, measured by reference to a Specified Investment Flow Through's ("SIFT") market capitalization as of the end of trading on October 31, 2006. The safe harbour calculation would include only the market value of the SIFT'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 2008, 2009 and 2010. 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;

(ii) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion into trust units of convertible debentures 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 these 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 SIFT.

The Trust's market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding publicly-traded Trust Units, was approximately $1.4 billion, which means the Trust's "safe harbour" equity growth amount for the period ending December 31, 2007 is approximately $560 million, and for each of calendar 2008, 2009 and 2010 is an additional approximately $280 million, not including equity issued to replace debt that was outstanding on October 31, 2006, including convertible debentures.

These guidelines could adversely affect the Trust's access to capital, the cost of raising capital, and the Trust's ability to undertake more significant acquisitions. It is not known at this time when the October 31 Proposals will be enacted by Parliament or whether the October 31 Proposals will be enacted in the form currently proposed.

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

Compliance with health, safety and environmental laws and regulations could materially increase our costs. We will incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and health and safety. These include costs to reduce certain types of air emissions and discharges and to remediate contamination at various facilities and third party sites where our products or wastes will be handled or disposed.

We are subject to statutory strict liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of our licenses. As a result, anyone who suffers losses or damages as a result of pollution caused by our operations can claim compensation without needing to demonstrate that the damage is due to any fault on our part.

New laws and regulations, tougher requirements in licensing, increasingly strict enforcement of, or new interpretations of, existing laws and regulations and the discovery of previously unknown contamination may require future expenditures to:

- modify operations;
- install pollution control equipment;
- perform site clean-ups; or
- curtail or cease certain operations.

For example, the Canadian government has adopted the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change. As a result, new requirements and regulations may be implemented which could require us to incur significant costs to comply. In addition, increasingly strict environmental requirements affect product specifications and operational practices. Future expenditures to meet such specifications could have a material adverse effect on our operations or financial condition. Any abandonment, remediation and restoration or other costs we incur will reduce distributions to Unitholders.

The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements such as those proposed, and those in effect, in the Climate Change and Emissions Management Act (Alberta) may require the reduction of emissions or emissions intensity produced by our operations and facilities. The direct or indirect costs of these regulations may adversely affect our business.

The Trust Units may cease to be qualified investments under the *Income Tax Act* (Canada) which could materially adversely affect the market for Trust Units.

The *Income Tax Act* (Canada) imposes penalties for the acquisition or holding of non-qualified investments by registered retirement savings plans, deferred profit sharing plans, registered retirement income funds and registered education savings plans. Should the Trust Units become non-qualified investments for the purpose of being held in such plans, the plans might become liable for penalties and the market for the Trust Units may be adversely affected.

RECORD OF CASH DISTRIBUTIONS

We distribute cash to Unitholders out of the income and other amounts we receive, indebtedness of POT to us, our other assets and other investments, less expenses and any other amounts we are permitted to deduct or must withhold or pay to third parties. We borrow funds from time to time to finance the purchase of properties or corporate entities, for capital expenditures or for other financial obligations or expenditures in respect of properties held by us or for working capital purposes. The credit facilities contain provisions which restrict the ability of the Trust to pay distributions to Unitholders in the event of the occurrence of certain events of default.

The historical distributions described above may not be reflective of future distributions, which will be subject to review by the board of directors of the Administrator taking into account the prevailing circumstances at the relevant time. See **RISK FACTORS**.

The accompanying table summarizes cash distributions to Unitholders since for each of the last three years:

For the Period Ended	Payment Date	Distribution per Trust Unit
January 30, 2004	February 16, 2004	$0.200
February 27, 2004	March 15, 2004	$0.160
March 31, 2004	April 15, 2004	$0.160
April 30, 2004	May 17, 2004	$0.160
May 31, 2004	June 15, 2004	$0.160
June 30, 2004	July 15, 2004	$0.180
July 31, 2004	August 16, 2004	$0.200
August 29, 2004	September 15, 2004	$0.200
September 30, 2004	October 15, 2004	$0.200
October 31, 2004	November 15, 2004	$0.200
November 28, 2004	December 15, 2004	$0.200
December 31, 2004	January 15, 2005	$0.200
January 30, 2005	February 15, 2005	$0.220
February 27, 2005	March 15, 2005	$0.220
March 31, 2005	April 15, 2005	$0.220
April 30, 2005	May 16, 2005	$0.220
May 31, 2005	June 15, 2005	$0.220
June 30, 2005	July 15, 2005	$0.220
July 30, 2005	August 15, 2005	$0.220
August 31, 2005	September 15, 2005	$0.220
September 30, 2005	October 17, 2005	$0.240
October 29, 2005	November 15, 2005	$0.240
November 30, 2005	December 15, 2005	$0.240
December 31, 2005	January 16, 2006	$0.240
January 31, 2006	February 15, 2006	$0.240
February 28, 2006	March 15, 2006	$0.240
March 31, 2006	April 17, 2006	$0.240
April 28, 2006	May 15, 2006	$0.240
May 31, 2006	June 15, 2006	$0.240
June 30, 2006	July 17, 2006	$0.240
July 31, 2006	August 15, 2006	$0.200
August 31, 2006	September 15, 2006	$0.200
September 29, 2006	October 16, 2006	$0.200
October 31, 2006	November 15, 2006	$0.200
November 30, 2006	December 15, 2006	$0.200
December 29, 2006	January 15, 2007	$0.200
January 31, 2007	February 15, 2007	$0.200
February 28, 2007	March 15, 2007	$0.140

MARKET FOR SECURITIES

Our Trust Units are listed and posted for trading on the TSX under the symbol **PMT.UN**. The following table sets out the price range and trading volume of Trust Units as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2006			
January	22.59	21.51	4,947,164
February	22.19	17.55	8,573,625
March	20.95	17.82	7,158,308
April	21.76	19.76	4,294,231
May	20.34	17.85	5,305,511
June	19.40	16.70	4,480,715
July	20.06	17.64	3,784,502
August	20.97	19.24	4,744,362
September	19.89	15.36	6,394,797
October	18.33	14.37	8,266,347
November	15.59	11.58	11,703,579
December	15.10	12.39	5,497,360
2007			
January	12.99	11.45	6,386,962
February	12.98	11.25	6,089,648

The 8% Convertible Debentures are listed and posted for trading on the TSX and trade under the symbol **PMT.DB**. The following sets out the price range and trading volume of the 8% Convertible Debentures as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2006			
January	155.25	150.07	167,000
February	154.44	141.64	213,000
March	143.00	136.00	85,000
April	150.00	139.84	144,000
May	142.77	128.23	239,000
June	133.00	117.77	141,000
July	132.00	127.15	45,000
August	142.77	133.23	482,000
September	127.00	110.00	15,000
October	120.50	109.27	145,000
November	119.99	108.01	151,000
December	108.01	101.00	50,800
2007			
January	101.16	101.16	15,000
February	108.00	103.00	62,000

On April 26, 2005 PET issued 6.25% Convertible Debentures, which are listed and posted for trading on the TSX and trade under the symbol **PMT.DB.A**. The following sets out the price range and trading volume of the PMT.DB.A 6.25% Convertible Debentures as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2006			
January	116.29	111.69	2,275,800
February	114.00	104.50	3,580,700
March	109.70	105.00	2,454,000
April	111.00	106.65	1,241,000
May	106.75	100.66	2,963,700
June	106.50	101.50	3,852,200
July	106.00	102.01	460,000
August	109.64	103.65	1,403,000
September	107.00	100.65	2,869,000
October	103.45	100.00	1,912,000
November	101.00	95.10	2,909,000
December	99.50	97.50	1,129,000
2007			
January	99.99	96.52	1,421,000
February	103.64	95.51	1,598,500

On April 6, 2006 PET issued 6.25% Convertible Debentures, which are listed and posted for trading on the TSX and trade under the symbol **PMT.DB.B**. The following sets out the price range and trading volume of the PMT.DB.B 6.25% Convertible Debentures as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2006			
April 6-30	102.75	100.50	34,444,000
May	101.90	99.75	7,983,000
June	101.80	99.00	3,359,000
July	102.00	100.19	1,980,000
August	102.00	99.75	2,002,000
September	102.25	99.01	2,549,000
October	100.50	97.01	3,697,000
November	99.24	95.00	2,384,000
December	98.00	95.50	1,348,000
2007			
January	98.00	95.50	1,428,000
February	97.45	95.75	2,360,500

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

We are authorized to create and issue an unlimited number of Trust Units and an unlimited number of special voting units ("**Special Voting Units**") described below. We are authorized to create, issue, sell and deliver Trust Units, including rights, warrants, special warrants, subscription receipts, instalment receipts, exchangeable securities or other securities to purchase, convert, redeem or exchange into Trust Units or other securities, including debt convertible into Trust Units or other securities of PET, on such terms and conditions as the Administrator may determine. All Trust Units outstanding from time to time are entitled to receive an equal undivided share of any distributions from the Trust. In the event that PET ceases to exist or is wound up, each Trust Unit entitles its holder to an equal undivided share in any amounts distributed upon such cessation or winding-up after satisfaction of all liabilities and provision for indemnities. All Trust Units are of the same class with equal rights and privileges. Each Trust Unit is transferable, fully paid and non-assessable and entitles its holder to receive notice of, attend and vote at all meetings of the Unitholders. The Trust Units do not entitle the Unitholder to any conversion, retraction, redemption or pre-emptive rights, except for the rights referred to under **Redemption Right**. No fractional Trust Units will be issued or transferred except for the purposes of distributions of Trust Units referred to in **Distributions**.

In order to allow us flexibility in pursuing corporate acquisitions, the Trust Indenture allows for the creation and issuance of Special Voting Units. If and when we issue Special Voting Units, it will likely be to a trustee for the benefit of the holders of securities which are exchangeable for Trust Units, entitling the trustee to such number of votes at meetings of Unitholders as the Administrator's board of directors ("**Board**" or "**Board of Directors**") may prescribe. The Special Voting Units give us the flexibility to acquire the securities of another issuer in exchange for securities that are ultimately exchangeable for Trust Units. The Board will set the voting rights or other rights and the terms upon which we issue Special Voting Units. The Special Voting Units will not entitle the holder to any distributions of any nature whatsoever from PET or to any beneficial interest in any of our assets during PET's existence or upon PET's termination or winding-up. To the extent that we issue Special Voting Units, the voting power of existing Unitholders will be reduced.

The legal ownership of our assets and the right to conduct the undertaking of PET, subject to the limitations contained in the Trust Indenture, are vested exclusively in the Trustee or such other person as the Trustee determines. The Trust Units are personal property and confer upon Unitholders only the interest and rights specifically set forth in the Trust Indenture. Except as specifically set out in the Trust Indenture, no Unitholder has or is deemed to have any right of ownership in any of our assets. Under the Trust Indenture material amendments to the Trust Indenture affecting the rights of Unitholders require the approval of Unitholders by a resolution passed at a meeting of Unitholders by more than 66⅔% of the votes cast ("**Special Resolution**").

The Trust Units do not represent a traditional investment and you should not view them as "shares" in PET. See **RISK FACTORS**.

The 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. Further, none of PET, POT or the Administrator is a trust company and, accordingly, none of them are registered under any trust and loan company legislation as they do not carry on, or intend to carry on, the business of a trust company.

Constraints For Non-Resident Unitholders

In order for us to maintain our status as a mutual fund trust under the *Income Tax Act* (Canada), we must not be established or maintained primarily for the benefit of persons who are non-residents of Canada for the purposes of the *Income Tax Act* (Canada) (referred to in this section as "**Non-Residents**"). The Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are Non-Residents. We may require Unitholders to provide a declaration (referred to in this section as a "**Residence Declaration**") specifying whether or not they are Non-Residents. If, at any time, the Trustee determines that the beneficial owners of 49% or more of the Trust Units are or may be Non-Residents or that such a situation is imminent, the Trustee may announce publicly such determination. After such determination the Trustee will refuse any subscription or transfer not accompanied by a Residence Declaration confirming Canadian residence. If the Trustee determines that Non-Residents hold a majority of the Trust Units, the Trustee may send a notice to Non-Residents requiring them to sell all or a portion of their Trust Units within 60 days. The Trustee will send notices only to as many Non-Resident Unitholders and with respect to only so many Trust Units as may be reasonably necessary to ensure that the number of Trust Units held by Non-Residents would be reduced, as far as the Trustee is aware, to no greater than 48% of the Trust Units then outstanding. The Trustee will use reasonable commercial efforts to ensure that its actions in this regard will not reduce the number of Trust Units held by Unitholders who are or may be Non-Residents, so far as the Trustee is aware, to less than 40% of the Trust Units outstanding. Following the 60 days, to the extent Non-Resident Unitholders have not sold the specified number of Trust Units, the Trustee may sell Trust Units on the Non-Residents' behalf unless the Non-Residents provide satisfactory evidence that they are Canadian residents. Until the Trustee sells such Trust Units, the Trustee will suspend the voting and distribution rights associated with those Trust Units. The Trustee will sell the Trust Units on any stock exchange on which the Trust Units are then listed. Such Trust Units will be sold on the basis of an inverse order to the order of acquisition by such Non-Residents until the Trustee, in its sole discretion, determines that the restrictions on ownership imposed on PET are no longer in danger of being violated. The Trustee will pay the net proceeds of such sale to the Non-Resident upon the Non-Resident's surrender of its banknote form of certificate representing the Trust Units (the "**Unit Certificate**").

Ratings

None of our securities have been formally rated by any accredited rating agency.

Unitholder Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, will be subject to any liability to any person:

- in connection with our assets, obligations or affairs; or
- with respect to any act any person performs pursuant to the Trust Indenture; or
- with respect to any act or omission of any person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred under the Trust Indenture; or
- with respect to any transaction any person enters into pursuant to the Trust Indenture.

Further, Unitholders, in their capacities as such, are not contractually liable to indemnify any person for any of the above liabilities, including taxes any person may incur on our behalf. If, however, a court assesses any of such liabilities against a Unitholder, those liabilities will be enforceable only against and will only be satisfied out of our assets. We will be liable to the Unitholders and indemnify the Unitholders, to the extent of its assets, from liability arising as a result of the Unitholders not having such limited liability. The Trust Indenture provides that every written contract entered into, by, or on our behalf must include a provision substantially to the effect that any obligation created under such contract will not be binding upon Unitholders personally.

Notwithstanding the terms of the Trust Indenture, Unitholders, in their capacities as such, may not have the same protection from our liabilities that a shareholder would have from the liabilities of a corporation. Unitholders may face personal liability for claims against us, including contract claims, tort claims, environmental claims, claims for taxes and possibly other statutory liabilities. Unlike many other royalty trusts and income funds, our structure does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to Unitholders.

Note, however, that on July 1, 2004 the *Income Trust Liability Act* (Alberta) came into force creating a statutory limitation on the liability of unitholders of Alberta income trusts such as the Trust. The legislation provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee. The implementation of the *Income Trust Liability Act* (Alberta) assists in mitigating the effect of the Trust's structure and its lack of an inter-positioned limited liability entity for claims after July 1, 2004. This legislation has not been subject to interpretation by courts in the Province of Alberta.

We intend to conduct our business so as to avoid, as far as reasonably possible, any material risk of liability to the Unitholders for claims against us. We have obtained insurance, in amounts available and appropriate, for the operations of POT and the Administrator. However, the amounts and types of insurance obtained may not be sufficient to provide full coverage.

Distributions

We distribute cash to the Unitholders out of the income and other amounts it receives from any royalties, indebtedness of POT to PET, our other assets and other investments, less expenses and any other amounts we are permitted to deduct or must withhold or pay to third parties.

The material sources of our cash flow are currently limited to:

- royalty income it receives on the POT Royalty;
- interest and principal POT pays respecting indebtedness of POT to us from time to time to finance our operations; and
- trust income POT distributes to us as its sole beneficiary.

Our material expenses are currently substantially limited to:

- interest, principal and fees paid to its lenders;
- trustee fees and expenses;
- expenses related to printing and other matters in connection with communicating with and sending distributions to the Unitholders; and
- general and administrative expenses.

POT may apply some or all of its cash flow to capital expenditures to develop POT's oil and natural gas properties or to acquire additional oil and natural gas properties. This would effectively reduce the amounts POT pays to us under the POT Royalty as well as reduce POT's distributions to us as its sole beneficiary and our distributions to Unitholders. Under the terms of our credit facility, if our lenders determine the borrowing base has been exceeded, we will be precluded from providing distributions on the Trust Units until the borrowing base is no longer in a shortfall position. Our lenders may also restrict our ability to pay distributions in circumstances when we are in breach or default of our agreements.

We will pay such cash distributions on the 15th day of each month or, if such day is not a business day, the next following business day. Each Unitholder has the right to enforce payment of any distribution at the time the amount becomes payable. Any of our income (as computed under the *Income Tax Act* (Canada) or net realized capital gains not otherwise distributed to Unitholders in a calendar year shall, without any further action on the part of the Administrator, be due and payable to Unitholders of record at the close of business on December 31 in each year. Absent a demand from a Unitholder to enforce payment, such amounts will be paid to Unitholders on or before February 15 of the following year. Upon the Administrator's written direction, the Trustee may change the dates on which we pay distributions, at any time, subject to having given the Unitholders not less than 60 days' prior written notice. Additionally, upon the Administrator's written direction, the Trustee may change the record date for the payment of distributions at any time, upon compliance with any requirements of applicable law or the rules of any stock exchange.

Where:

- between record dates for distributions, we have paid cash in respect of Trust Units tendered for redemption (see **Redemption Right**), we may, on the next distribution date, reduce the cash amount of the aggregate distribution at that time by the cash amount paid for the redemptions and include a distribution to Unitholders of additional Trust Units in place of that amount; and

- we determine we do not have sufficient cash to pay the full distribution to be made on a distribution date (or on any other date on which any other distribution is payable under the Trust Indenture), or if any cash distribution would be contrary to, or would not allow the Trustee to comply with, its credit facilities, the distribution may, at the option of the Administrator, include a distribution to Unitholders of additional Trust Units having a value equal to the cash shortfall and the amount of cash distributed will be reduced by the cash shortfall.

After any such distribution we may consolidate the Trust Units so that each Unitholder has the same number of Trust Units as they held immediately prior to such distribution except where tax is required to be withheld in respect of the Unitholder's share of the distribution. The value of such additional Trust Units will be based on the closing trading price thereof on the principal stock exchange on which they are listed on the applicable distribution date or otherwise as the Trustee determines. The net effect of the foregoing is that Unitholders would not receive all or a portion of the cash which would have been distributed to them, with no corresponding increase in their ownership percentage in PET. Where amounts so distributed represent income, Unitholders who are neither resident nor deemed to be resident in Canada for the purposes of the *Income Tax Act* (Canada), including any Unitholder that is a partnership, any member of which is neither resident nor deemed to be resident in Canada for the purposes of the *Income Tax Act* (Canada) ("**Non-Resident Unitholders**"), will be subject to withholding tax and the consolidation will not result in such Non-Resident Unitholders holding the same number of Trust Units. Such Non-Resident Unitholders will be required to surrender the certificates (if any) representing their original Trust Units in exchange for a certificate respecting their post-consolidation Trust Units.

The Trust Indenture provides that the Trustee may deduct or withhold from any amounts payable to Unitholders, including payments or deliveries due to Unitholders who have exercised redemption rights, amounts required by law to be withheld from those payments. If withholding is required on any distributions (including distributions of Trust Units) or redemption amounts and the Trustee is or was unable to withhold, or otherwise did not withhold, taxes from a particular payment, the Trustee is permitted to withhold the applicable amounts from other distributions to the Unitholder or sell such number of Trust Units being distributed to Unitholders as are necessary to satisfy the Trustee's withholding tax obligations with respect to the Unitholder and all of the Trustee's reasonable expenses with respect thereto.

Redemption Right

Unitholders may redeem their Trust Units at any time by delivering their Unit Certificates to the Trustee, together with a properly completed notice requesting redemption in a form acceptable to us. Once we have received all required documents, Unitholders have no rights with respect to the Trust Units tendered for redemption, other than a right to receive the redemption amount, which amount per Trust Unit will be the lesser of 90% of the weighted average trading price of the Trust Units on the principal market on which they are traded for the 10 day period after the Trust Units have been validly tendered for redemption and the "closing market price" of the Trust Units. The redemption amount will be payable on the last day of the following calendar month. The "closing market price" will be the closing price of the Trust Units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or, if there was no trade of the Trust Units on that date, the average of the last bid and ask prices of the Trust Units on that date.

In the event that the aggregate redemption value of Trust Units tendered for redemption in a calendar month exceeds $100,000 and the Administrator does not exercise its discretion to waive such $100,000 limit, we will not use cash to pay the redemption amount for any of the Trust Units tendered for redemption in that month. Instead, we will pay the redemption amount for those Trust Units, subject to compliance with applicable laws, including securities laws, of all jurisdictions, and the receipt of all applicable regulatory approvals, by the issuance of promissory notes of PET (referred to in this section and elsewhere as the "**Notes**" or the "**PET Notes**") to the tendering Unitholders on the last day of the next calendar month. The Notes will have an aggregate principal amount equal to the aggregate redemption amount of the Trust Units tendered by the Unitholder for redemption. If applicable laws prevent the issuance of these Notes to a Unitholder, the Trustee will authorize the payment of the redemption amount to that Unitholder in future months. Under the terms of our credit facility, if our lenders determine the borrowing base has been exceeded or we are in breach or default of our agreements, we will be precluded from paying cash for redemptions of Trust Units.

Notwithstanding the above, if, at the time Trust Units are tendered for redemption:

- in the discretion of the Administrator, the trading price of the Trust Units on the stock exchange on which the Trust Units are listed does not represent the fair market value of the Trust Units; or

- the normal trading of the Trust Units on the stock exchange on which they are listed is suspended or halted on the date the Trust Units are tendered for redemption or for more than five trading days during the ten trading day period after that date;

the redemption amount for each of those Trust Units will be equal to 90% of the fair market value thereof as determined by the Administrator. We will pay such redemption amount on the last day of the third month following the month in which those Trust Units were tendered for redemption. At our option , we will pay the redemption amount in cash or, subject to compliance with applicable laws, including securities laws, of all jurisdictions, and the receipt of all applicable regulatory approvals, the delivery to the Unitholder of PET Notes having an aggregate principal amount equal to the aggregate redemption amount of the Trust Units tendered by the Unitholder for redemption.

The Notes delivered as set out above will be unsecured and bear interest at a market rate of interest to be determined at the time of issuance by the Board of Directors, based on the advice of an independent financial advisor, with the interest to be payable monthly. The Notes will be subordinated and, in certain circumstances, postponed to all our indebtedness. Subject to prepayment, the Notes will be due and payable 5 years after issuance.

The Notes will be issued under and subject to the terms of a note indenture to be entered into prior to their issuance which indenture may provide for the issuance of Notes in series or otherwise. The trustee under the note indenture will be obligated under an agreement with our lenders to subordinate, and in certain circumstances to postpone, the payment of such Notes. Such Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, registered education savings plans and deferred profit savings plans if we cease to qualify as a mutual fund trust under the *Income Tax Act* (Canada) or if the Trust Units cease to be listed.

The Trustee has the discretion to designate a portion of any redemption payment as income, however, any portion designated as income will not reduce the amount of any declared and unpaid income distribution that the Unitholder may be entitled to receive at the time of redemption. In such case, the Unitholder would receive full payment of both the redemption amount (however designated) and the unpaid income distribution.

We expect that the redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. We will not list the Notes referred to above on any stock exchange and no market will exist for them. The Notes may be subject to resale restrictions under applicable securities laws.

ESCROWED SECURITIES

To the knowledge of the Administrator, none of our securities are held in escrow.

DIRECTORS AND OFFICERS

Unitholders will vote, or withhold from voting, on an annual basis to authorize and direct the Trustee to pass a resolution on our behalf for the election of directors of the Board of the Administrator proposed by management of the Administrator. None of the constating documents of the Administrator restrict the directors' ability to vote compensation to themselves or any members of their body provided a regular quorum is present at a meeting of directors. The Administrator's by-laws grant broad borrowing powers to the Board which the Board may delegate to any one or more directors or officers of the Administrator. The Administrator does not have any mandatory retirement age for members of the Board and does not require them to own any Trust Units to be qualified to act as a director. The directors and officers of the Administrator are set out in the table below as are their municipalities of residence and present positions with the Administrator:

Name and Province and Country of Residence	Position held with the Administrator and Period Served as a Director [7]	Principal Occupations During the Past Five Years
Clayton H. Riddell Alberta, Canada	Executive Chairman of the Board and Director since June 28, 2002	Mr. Riddell has been the Executive Chairman of the Board of Directors of the Administrator since June 28, 2002, and was the Chief Executive Officer until May 9, 2005. He has been Chairman of the Board and Chief Executive Officer of Paramount Resources Ltd. since 1978; until June 2002 he was also the President. He is a director and the Chief Executive Officer of MGM Energy Corp., a public oil and gas company. He is Chairman of the Board of Trilogy Energy Ltd., the administrator of Trilogy Energy Trust. Mr. Riddell is also the Chairman of the Board of Newalta Income Fund and its wholly–owned subsidiary, Newalta Corporation (a public industrial waste management and environmental services company), and a director of Duvernay Oil Corp. (a public oil and gas exploration and development company).
Susan L. Riddell Rose[4] Alberta, Canada	President, Chief Executive Officer; Director since June 28, 2002	Ms. Riddell Rose has been the President and Chief Executive Officer of the Administrator since May 9, 2005. Prior to that time, Ms. Riddell Rose was the President and Chief Operating Officer of the Administrator since June 28, 2002. Prior to her current occupation, Ms. Riddell Rose was employed by Paramount Resources Ltd., culminating in the position of Corporate Operating Officer. She has also been a director of Paramount Resources Ltd. since 2000.
Cameron R. Sebastian Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of the Administrator since June 28, 2002. Prior to his current occupation, Mr. Sebastian was Vice President, Finance of Summit Resources Limited from June 2000 to June 2002. Prior to that, he was Vice President, Finance of Pursuit Resources Corp.
Gary C. Jackson Alberta, Canada	Vice President, Land, Legal and Acquisitions	Vice President, Land, Legal and Acquisitions of the Administrator since June 28, 2002. Prior to his current occupation, Mr. Jackson was Vice President, Land of Summit Resources Limited from May 2000 to June 28, 2002. Prior to that, he was Manager of Acquisitions and Divestitures, Joint Venture Mid-Stream Services at Petro-Canada Oil & Gas.
Kevin J. Marjoram Alberta, Canada	Vice President, Engineering and Operations	Vice President, Engineering and Operations of the Administrator since July 1, 2002. Prior to his current occupation, Mr. Marjoram was Engineering Manager, Northeast Alberta West Side for PRL from July 2000 to June 2002. Prior to that, he held positions in an operations managerial capacity for Spire Energy Ltd. and Northrock Resources Ltd.
Marcello M. Rapini Alberta, Canada	Vice President, Marketing	Vice President, Marketing since December 7, 2006. Prior to his current occupation, Mr. Rapini worked for the Administrator from December 15, 2005 as Manager, Marketing. From November 2004 to November 2005 Mr. Rapini was Senior Trader with Eagle Energy Marketing Canada. From 2003 to 2004 he worked as a Senior Trader and Vice President Trading with Sempra Energy Trading, and from 1996 to 2002 was Senior Trader with Mirant Energy Marketing Ltd.

Name and Province and Country of Residence	Position held with the Administrator and Period Served as a Director (7)	Principal Occupations During the Past Five Years
Donald J. Nelson(1)(2)(4)(8) Alberta, Canada	Director since June 28, 2002	Mr. Nelson is President of Fairway Resources Inc., an oil and gas consulting firm. Fairway Resources Inc. was retained as consultant for Hawker Resources Inc. from November 25, 2004 to March 22, 2005. During this time Mr. Nelson was acting Senior Vice President and Chief Operating Officer of Hawker Resources Inc. Prior to his current occupation, Mr. Nelson held the consecutive positions of Vice President, Operations and President and Director with Summit Resources Limited from July 1996 to June 2002.
John W. (Jack) Peltier(1)(2)(4)(8) Alberta, Canada	Director since June 28, 2002	Since 1978, Mr. Peltier has been the President of Ipperwash Resources Ltd., a private investment company. He was Chairman of the Board of Trustees of Request Income Trust (March 2001 to January 2002); director and then Chairman of the Board of EnerMark Inc. and concurrently of the Board of Trustees of EnerMark Income Fund (1986 to June 2001); director of Enerplus Resources Corporation and concurrently a member of the Board of Trustees of Enerplus Resources Fund (May 2000 to June 2001); director of Thunder Energy Ltd. (now Thunder Energy Trust) (October 1995 to May 2006); and director of Bow Valley Energy Ltd. (1996 to February 2002; May 2005 to current). Mr. Peltier has also been a director of the following public entities: Courage Energy Inc. (November 2000 to July 2001) and Manhattan Resources Ltd. (October 2001 to January 2003).
Karen A. Genoway(2)(3)(5)(8) Alberta, Canada	Director since June 28, 2002	Ms. Genoway is a professional landman with over 26 years experience in the oil and natural gas industry. Currently, she is the Vice President, Land for Onyx Oil & Gas Ltd., a private oil and gas company. From February 2001 to January 2002, she was Vice President of Request Management Inc., manager of Request Income Trust. Ms. Genoway was with the Enerplus Group of Companies where she held the positions of Senior Vice President (1997 to 2000), Vice President Land (1989 – 1997) and Land Manager (1987 – 1989).
Randall E. Johnson(1)(3)(5)(8) Alberta, Canada	Director since June 20, 2006	Mr. Johnson has been an independent businessman since 2005. Prior to that he was Managing Director of the Bank of Montreal's Corporate Banking group from 1996 to 2005. Mr. Johnson has served on the Board of Directors of Atlas Energy Ltd. (May 2005 to December 2006) and Dual Exploration Inc. (June 2005 to November 2006). Since January 2007 Mr. Johnson has also been a director of Magellan Resources Ltd., a privately held oil and gas company.
Howard R. Ward(3)(4)(5)(8) Alberta, Canada	Director since June 28, 2002	Mr. Ward has been a partner with International Energy Counsel LLP, a law firm, since December 2002. Prior thereto, Mr. Ward was counsel with the law firm McCarthy Tétrault LLP from June 2002 to December 2002. Prior to that, he was counsel with Donahue and Partners LLP and, for more than 22 years, partner with Burstall Ward, Barristers and Solicitors. He has been a member of the Law Society of Alberta since 1975. He also has served as a director of the following publicly traded entities: Blue Sky Resources Ltd. (July 1999 to July 2000); Cabre Exploration Ltd. (June 1981 to December 2000); Jet Energy Corp. (August 1995 to November 1999); and Tuscany Resources Ltd.,(October 1997 to October 2001).

Notes:

(1) Member of the Audit Committee.

(2) Member of the Reserves Committee.

(3) Member of the Corporate Governance Committee.

(4) Member of the Environmental, Health and Safety Committee.

(5) Member of the Compensation Committee.

(6) The Administrator does not have an executive committee.

(7) The terms of office of all directors of the Administrator will expire on the date of the next annual Unitholders' meeting of the Administrator.

(8) Mr. Nelson, Mr. Peltier, Ms. Genoway, Mr. Johnson and Mr. Ward are independent, non-employee directors. Non-employee directors receive directors' fees of $10,000 per year plus $1,000 per meeting. They also receive Trust Unit Incentive Rights under our Unit Incentive Plan. In addition, the chair of the Audit Committee receives $10,000 per annum, and the chair of every other committee receives $5,000 per annum. Non-employee directors have received Trust Unit Incentive Rights with various vesting provisions and exercise prices per annum since the inception of the Trust. The independent directors other than Mr. Johnson received 15,000 Trust Unit Incentive Rights in the first year of the Trust and have received annual top up grants of 3,750 additional Trust Unit Incentive Rights for the years up to and including 2005. In 2006, the Independent Directors received a top up grant of 12,500 Trust Unit Incentive Rights.

The directors and officers of the Administrator, as a group, beneficially own, directly or indirectly, or exercise control or direction over, an aggregate of 21,672,193 Trust Units as of March 13, 2007 representing 25.2 percent of the outstanding Trust Units.

Each of the senior officers listed above devote their full time efforts to POT, PET and the Administrator.

Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions

No director or officer of the Administrator, or a shareholder holding a sufficient number of securities of the Administrator to affect materially the control of the Administrator is, or within the last ten years has been, a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied us access to any statutory exemption for a period of more than 30 consecutive days or, within a year of such person ceasing to act in that capacity or within the 10 years prior to the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of that person.

No director or officer of the Administrator, or a shareholder holding a sufficient number of securities of the Administrator to affect materially the control of the Administrator, has been subject to any penalties or sanctions under securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There may be situations in which the interests of the Administrator's management will conflict with those of the Unitholders. Certain members of management own oil and natural gas properties that do not form part of the properties held by POT. Certain members of management may also acquire interests in energy-related businesses for their own account and on behalf of persons other than the Unitholders.

Generally, management will carry on our activities on behalf of the Unitholders. At times, however, certain members of Management or certain directors may act in contradiction to or in competition with the interests of the Unitholders when acting on behalf of other industry participants. Potential conflict of interest situations are required to be disclosed in accordance with our Code of Business Conduct. The Administrator has executed indemnity agreements with each of the directors and officers of the Administrator containing such terms and conditions as are standard in such agreements.

In resolving conflicts, management will deal fairly and in good faith with all interested parties. The Administrator's Board of Directors will require the facts and substances of any particular conflict be fully disclosed and will use all reasonable efforts to resolve conflicts in a manner that will treat PET or POT, as the case may be, and the other interested party fairly. All of our ongoing and future affiliated transactions will be made or entered into on terms that are no less favourable to us than those that we can obtain from unaffiliated third parties. All ongoing and future affiliated transactions and any forgiveness of loans must be approved by a majority of the independent members of the Board of Directors.

We will resolve conflicts between PET and the Administrator's officers and directors, including conflicts relating to corporate opportunities, in accordance with all applicable legislation and on the advice of counsel as required. Under the ABCA, a director is required to disclose to the Board any interest in any material contract or proposed material contract with the Administrator and may be required to refrain from voting on any resolution to approve such contract. Members of the Board may serve as directors or officers of entities which compete with us. We cannot assure that such Board members will make us aware of opportunities they identify.

As at March 13, 2007, we are not aware of any existing or potential material conflicts of interest between the Trust or the Administrator or a subsidiary thereof and a director or officer of the Administrator or of a subsidiary of the Trust or Administrator. See **RISK FACTORS**.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The mandate and responsibilities of our audit committee (the "**Audit Committee**") are set out in the Audit Committee Charter housed in our Corporate Governance Directors' Manual. The Audit Committee Charter is set out in Appendix "E" to this annual information form, which Appendix is incorporated in this annual information form by reference.

Audit Committee

The Audit Committee reviews and recommends to the Board the approval of the annual and interim financial statements, the associated management's discussion and analysis and related financial disclosure to the public and regulatory authorities. It is responsible for the engagement of our external auditors, upon approval by Unitholders, including fees paid for the annual audit and interim financial reviews, and pre-approves non-audit services. The committee communicates directly with the auditors and reviews programs and policies regarding the effectiveness of internal controls over our accounting and financial reporting systems. It also reviews insurance coverage and directors' and officers' liability insurance. The Audit Committee must liaise with the reserves committee on matters relating to reserves valuations which impact our financial statements.

Composition of the Audit Committee

The Audit Committee consists of three members: John W. (Jack) Peltier, Donald J. Nelson and Randall E. Johnson. Mr. Peltier is Chair of the Audit Committee. Each of the members of the Audit Committee is independent and financially literate in accordance with the meanings set out National Instrument 52-110 *Audit Committees*.

Relevant Education and Experience

John W. (Jack) Peltier

Mr. Peltier graduated from the Royal Military College of Canada with a Bachelor of Science degree and Queen's University at Kingston with an M.B.A. Mr. Peltier received his Chartered Financial Analyst designation in 1974 and is a member of the CFA Institute. Since 1978 he has been President of Ipperwash Resources Ltd. and predecessor companies, a private company providing management and financial consulting services. From March 2001 he was a trustee and then Chairman of the Board of Trustees of Request Income Trust until its acquisition by Pulse Data Inc. in January 2002. From 1986 to June 2001 he was a member and then Chairman of the board of directors of Enermark Inc. and concurrently of the Board of Trustees of Enermark Income Fund. From May 2000 to June 2001 he was a member of the board of directors of Enerplus Resources Corporation, and concurrently a member of the Board of Trustees of Enerplus Resources Fund. The aforementioned entities merged to continue as Enerplus Resources Fund in June 2001. From July 1995 to October 1996 he was the Chief Financial Officer of Bow Valley Energy Ltd. where he was a director from 1996 to February 2002 and rejoined the board as a director on May 18, 2005. He has been a director of Masters Energy Inc since October 2004, a Trustee of Gienow Windows and Doors Income Fund since October 2004 and Ember Resources Inc. since July, 2005. In the past 5 years Mr. Peltier has also been a director on the board of the following public entities in addition to those described above: Thunder Energy Inc. from October 1995 to July 2005 when it was reorganized into Thunder Energy Trust (and then a trustee of Thunder Energy Trust until April 2006); Courage Energy Inc. (November 2000 to July 2001); and Manhattan Resources Ltd. (October 2001 to January 2003).

Donald J. Nelson

Mr. Nelson holds a diploma in Computer Technology from the Southern Alberta Institute of Technology, Calgary, Alberta (1969) and graduated from Notre Dame University, Nelson, British Columbia with a Bachelor of Science degree in Mathematics (1972). He is president of Fairway Resources Inc., a private firm providing consulting services to the oil and gas industry. Fairway Resources Inc. was retained as a consultant for Hawker Resources Inc. from November 25, 2004 to March 22, 2005. During this time Mr. Nelson was acting Senior Vice-President and Chief Operating Officer of Hawker Resources Inc. Mr. Nelson was with Summit Resources Limited from July 1996 until its acquisition by PRL in June of 2002, where he held the position of Vice President, Operations from July 1996 to September 1998 and President and Director from September 1998 to June of 2002. He is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and of the Society of Petroleum Engineers. Mr. Nelson is also currently a director of Taylor NGL Limited Partnership (May 2003 to present), Fairquest Energy Limited (May 2005 to present), Culane Energy Inc. (May 2003 to present) and Flagship Energy Inc (May 2005 to present).

Randall E. Johnson

Mr. Johnson graduated with a Bachelor of Science degree in Mathematics (1980) and a Masters of Business Administration degree (1982) from Brigham Young University in Provo, Utah. His 22 year career in Corporate Banking commenced with CIBC in 1982 in Calgary. In 1984, he moved to Bank of Montreal's Corporate Banking group where worked as an Associate from 1984 to 1987, Account Manager from 1987 to 1990, Director from 1990 to 1996, and then as Managing Director from 1996 to 2005. After retiring from Bank of Montreal in January 2005, Mr. Johnson joined the Board of Directors of three publicly traded oil and gas companies: Atlas Energy Ltd. (May 2005 to December 2006), Dual Exploration Inc. (June 2005 to November 2006), and Paramount Energy Trust (June 2006 to present). During the 2005-2006 school year, Mr. Johnson was a part-time faculty member of the Bisset School of Business at Mount Royal College. Since January 2007 Mr. Johnson has also been a director of Magellan Resources Ltd., a privately held company.

Pre-Approval of Policies and Procedures

We have adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP. The Audit Committee has established a budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee, but at the option of the Audit Committee it may cover a longer or shorter period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

The Audit Committee must pre-approve the provision of permitted services by KPMG LLP which are not otherwise pre-approved by the Audit Committee, including the fees and terms of the proposed services. Prohibited services may not be pre-approved by the Audit Committee.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were $518,000 in 2006 and $83,830 in 2005.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by our external auditor that are reasonably related to the performance of the audit or review of the financial statements that are not reported under ***Audit Fees*** above were $256,793 in 2006 and $209,625 in 2005. In 2006, we incurred fees for quarterly reviews and services provided with respect to a prospectus. In 2005, we incurred fees for quarterly reviews and services provided with respect to a prospectus and in connection with the gas over bitumen issue.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditor for tax compliance, tax advice and tax planning were $70,622 in 2006 and $39,756 in 2005.

These services relate to the determination and reporting of taxability of security distributions for each of Canada and the United States and the preparation and filing of Canadian trust and corporate income tax returns.

All Other Fees

No fees were billed in each of the last two fiscal years for products and services provided by our external auditor other than services reported above.

DISTRIBUTION REINVESTMENT AND OPTIONAL TRUST UNIT PURCHASE PLAN

PET has established a Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "**DRIP Plan**"). Under the DRIP Plan, eligible Unitholders have the opportunity to reinvest monthly cash distributions to acquire additional Trust Units at 94 percent of the treasury purchase price, which is defined as the daily volume weighted average trading prices of the Trust Units for the 10 trading days immediately preceding a distribution payment date. As well, subject to thresholds and restrictions described in the DRIP Plan, it contains a provision for the purchase of additional Trust Units with optional cash payments of up to $100,000 per participant per financial year of PET to acquire additional Trust Units at the same six percent discount to the treasury purchase price. The aggregate number of DRIP Units that may be purchased in any financial year of PET will be limited based on the number of Trust Units issued and outstanding at the start of the financial year. As of March 13, 2007, the aggregate number of Trust Units that have been issued under the DRIP is 6,227,859. The aggregate number of Trust Units available for distribution under the DRIP Plan as of March 13, 2007 was 4,827,689. Participants will not have to pay any brokerage fees or service charges in connection with the purchase of Trust Units under the DRIP Plan.

We reserve the right to determine the number of Trust Units available for purchase under the DRIP Plan for any distribution payment date. In respect of any distribution payment date, if fulfilling all of the elections under the DRIP Plan would result in our exceeding the limitations on the number of Trust Units issuable under the DRIP Plan, then we will accept elections for the purchase of DRIP Units on such distribution payment: (i) first, from participants electing the distribution reinvestment option; and (ii) second, from participants electing the cash payment option. If we are unable to accept all elections in a particular category, then we will prorate purchases of DRIP Units on the applicable distribution payment date among all participants in that category according to the number of Trust Units they seek to purchase.

LEGAL PROCEEDINGS

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of the Administrator's directors and senior officers, any Unitholder who beneficially owns more than 10% of the outstanding Trust Units, or any known associate or affiliate of such persons, in any transaction since the beginning of our last completed financial year or in any proposed transaction which has materially affected or will materially affect us or the Administrator other than (i) certain insiders purchasing Trust Units and Convertible Debentures under the public offerings of such securities completed during 2004, (ii) certain insiders purchasing common shares of Severo Energy Corp. in 2006 by way of private placement and (iii) as disclosed herein.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are KPMG LLP, Chartered Accountants, Calgary, Alberta.

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Trust Units and Convertible Debentures.

MATERIAL CONTRACTS

Except for contracts we entered into in the ordinary course of business or otherwise disclosed in this annual information form, the only material contracts outstanding are the following:

1. the Trust Indenture;
2. the POT Indenture; and
3. the POT Royalty Agreement.
4. the 8% Convertible Debenture Trust Indenture
5. the 2005 6.25% Convertible Debenture Trust Indenture
6. the 2006 6.25% Convertible Debenture Trust Indenture

These documents can be found on SEDAR at www.sedar.com.

INTEREST OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Trust during, or relating to, the Trust's most recently completed financial year, and whose profession or business gives authority to the statement, report or valuation made by the person or company, are KPMG LLP, the Trust's independent auditors, McDaniel, the Trust's independent engineering evaluators and Prevent, the Trust's independent asset retirement obligation evaluators.

Interests of Experts

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

Neither KPMG LLP, McDaniel or Prevent, nor any director, officer or employee of KPMG LLP, McDaniel or Prevent, is or is expected to be elected, appointed or employed as a director, officer or employee of the Administrator or of any associate or affiliate of the Administrator.

KPMG LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

GOVERNMENT REGULATION

Various levels of government impose extensive controls and regulations on the oil and natural gas industry. Some of the more significant aspects are outlined below.

Regulatory Compliance Governed by AEUB

The AEUB regulates the development of Alberta’s natural energy resources. We are subject to, and are in material compliance with regulations, rulings and other requirements administered by the AEUB.

The most significant regulatory impact on us has been from the AEUB’s decisions and orders related to the shut-in of natural gas in favour of bitumen conversation. See **REGULATORY RULINGS – GAS OVER BITUMEN**.

The North American Free Trade Agreement

We are bound by the energy terms of the North American Free Trade Agreement (“**NAFTA**”), among the governments of Canada, the U.S. and Mexico. Canada is able to restrict exports or energy resources if the export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period), (ii) impose an export price higher than the domestic price, or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA contemplates a fair implementation of regulatory changes and minimal disruption of contractual arrangements.

Land Tenure

The governments of the western provinces own most of the crude oil and natural gas located in such provinces. These provincial governments grant rights to explore for and produce oil and natural gas for varying terms and on conditions set forth in legislation. Oil and natural gas located in such provinces can also be privately owned (freehold). Freehold rights owners may grant rights to explore for and produce oil and natural gas on negotiated terms.

Royalties and Incentives

In addition to federal regulations, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Negotiations between a freehold mineral owner and the lessee determines royalties payable on production from lands other than Crown lands. Government regulation determines Crown royalties which are generally calculated as a percentage of the gross production. The rate of Crown royalties payable depends in part on the prescribed reference prices (which represent the average prices for sale of specific commodities), well productivity, geographical location, field discovery date, the method of recovery and the type or quality of the petroleum product. The governments of Canada and Alberta have established incentive programs including royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced production projects.

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

Subject to various incentives, the Alberta Crown reserves a royalty to itself of between 15% and 30% in the case of new gas and between 15% and 35% in the case of old gas, depending upon a prescribed or corporate average reference price. A royalty exemption applies to gas produced from qualifying exploratory gas wells spud or deepened after July 31, 1985 and before June 1, 1988 up to a prescribed maximum amount.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under our equity compensation plans, as applicable, is contained in our management information and proxy circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided in our financial statements and management's discussion and analysis for the year ended December 31, 2006, which are set our in our 2006 Annual Report. Documents affecting the rights of securityholders, along with additional information relating to PET, can be found on SEDAR at www.sedar.com.

APPENDIX A

THE POT ROYALTY AGREEMENT

Grant of Royalty

Under the POT Royalty Agreement, POT granted the POT Royalty to us with respect to all petroleum and natural gas properties POT may acquire and hold from time to time. Pursuant to the POT Royalty, we are entitled to receive 99% of POT's net revenue from its petroleum and natural gas properties, less permitted deductions with respect to debt payments, capital expenditures and certain other amounts.

The POT Royalty does not constitute an interest in land. We generally are not entitled to take our share of production in kind or to separately sell or market our share of petroleum substances produced from POT's petroleum and natural gas properties, but can do so subject to certain conditions in the case of POT's insolvency.

Payment of Royalty Income

The royalty income POT pays to us pursuant to the POT Royalty Agreement with respect to a particular payment period will be paid in cash on the 15th day (or the next business day if the 15th is not a business day) of the following month. The POT Royalty Agreement allows the Board of Directors to elect payment periods and they have determined to make distributions on a monthly basis. The POT Royalty Agreement obligates POT to pay all Crown charges in respect of its petroleum and natural gas properties. We are required to reimburse POT for 99% of such charges that, prior to 2003, were not deductible for income tax purposes. At POT's option, such reimbursement may be set-off against amounts POT is obliged to pay us under the POT Royalty Agreement.

Deferred Purchase Price Obligation

The POT Royalty attaches to all petroleum and natural gas properties POT acquires from time to time. In recognition of this feature of the POT Royalty, the POT Royalty Agreement requires us to make certain royalty purchase payments in addition to the payment made upon the grant of the POT Royalty ("**Deferred Royalty Purchase Payments**") and are generally required in three circumstances. First, when POT acquires petroleum or natural gas properties, we must pay POT as a Deferred Royalty Purchase Payment 99% of the intangible cost of such properties that is not financed with indebtedness POT incurs or assumes. Second, when we raise equity by way of issuing Trust Units, POT may require us to make a Deferred Royalty Purchase Payment of up to the lesser of the net proceeds of that issuance and 99% of POT's debt that reasonably relates to petroleum or natural gas properties previously acquired or in respect of which POT has incurred capital expenditures for which we have not already paid a Deferred Royalty Purchase Payment. Third, POT may require us to fund, as a Deferred Royalty Purchase Payment, 99% of capital expenditures that POT proposes to incur in respect of the intangible costs associated with petroleum or natural gas properties, to the extent such expenditures are not financed with indebtedness.

As a result of the Deferred Royalty Purchase Payments and loans that we will from time to time make to POT, we will provide POT with 99% of the funding it requires to acquire petroleum and natural gas properties. POT will bear the remaining 1% of the cost of such properties and the entire cost of tangible equipment relating to any such properties utilizing its own working capital or funds it borrows for such purposes.

Acquisition of Properties

The POT Royalty Agreement permits POT to acquire petroleum or natural gas properties that have a reserve value that is 20% or less of the reserve value of all of POT's petroleum and natural gas properties without approval of the Administrator's Board of Directors. Acquisitions in excess of this amount must be approved by the Board. The Board may add to or change the foregoing restrictions on the acquisition of such properties.

Disposition of Properties

The POT Royalty Agreement permits POT to sell tangible and other properties related to its petroleum and natural gas properties and to license geological or other data it has rights to, so long as it acts reasonably and in accordance with prudent oil and gas industry practice. Generally, these properties will not be subject to the POT Royalty.

The POT Royalty Agreement permits POT to dispose of petroleum and natural gas properties that are subject to the POT Royalty and requires us to release the POT Royalty with respect to such dispositions provided that three conditions are met: (a) POT is of the reasonable opinion that such sale is in our best interest; (b) if the sale is comprised of assets having a reserve value of 20% or more of the reserve value of all of POT's petroleum and natural gas properties, the Board of Directors has approved the sale; and (c) if the sale is comprised of assets having a reserve value of 50% or more of the reserve value of all of POT's petroleum and natural gas properties, Unitholders have approved the sale by Special Resolution. Notwithstanding the foregoing, the POT Royalty Agreement provides that if our lenders act upon their security, they may dispose of POT's petroleum and natural gas properties and the associated POT Royalty without obtaining the approvals referred to above.

If POT sells any petroleum or natural gas rights, 99% of the net proceeds of the sale will, subject to the following, be allocated to us with respect to the POT Royalty, and 1% will be allocated to POT. POT will hold the proceeds of disposition allocated to us in trust and may pay such funds to us, set such funds off against any Deferred Royalty Purchase Payment we owe to POT or use such funds to acquire additional properties or maintain and develop existing properties.

Term of POT Royalty Agreement

The POT Royalty Agreement will continue in force for so long as POT owns any properties that are subject to such agreement, or holds any proceeds of disposition in trust for PET.

Credit Facilities

POT is authorized to borrow funds and grant security both with respect to its own borrowing and with respect to certain third party obligations it may from time to time guarantee, such as our debts, for the purpose of obtaining the credit necessary to acquire, develop and operate its properties.

THE TRUST INDENTURE

The following information summarizes the material information contained in the Trust Indenture. The Trust Indenture provides for the governance of the Trust. While this summary discusses all material information, it is not exhaustive and may not contain all of the information that is important to you.

General

We were established for the purposes of issuing Trust Units and acquiring and holding royalties and other investments including the entire beneficial interest in POT and the POT Royalty.

Subject to the provisions of applicable law, the Trust Indenture contains an acknowledgement that the directors and officers of the Administrator may be engaged directly or indirectly in the oil and gas industry and gas advisory and consulting businesses in Canada and elsewhere. Nothing in the Trust Indenture prohibits such persons from undertaking such engagements. The Trust Indenture specifies that the Administrator will require any such person to disclose to the Trustee any conflict of the interests of such persons with the interests of the Trust within a reasonable period of time after such person ascertains such conflict.

Canadian securities legislation puts reporting obligations on persons who acquire more than a certain percentage of our securities. Generally, no obligations are triggered until a threshold of 10% or more of the outstanding class of securities is acquired. The provisions dealing with reporting obligations are complex and persons approaching this threshold should consult with their professional advisors. There are also constraints on non-Canadian ownership of our securities. See **DESCRIPTION OF CAPITAL STRUCTURE Constraints – Non-Resident Holders**.

Investment Powers

Under the Trust Indenture, we have broad powers to invest funds not distributed to Unitholders, including the power:

- to fund POT or any subsidiary of ours to enable them to further develop their oil and natural gas assets or to acquire, directly or indirectly, further producing assets and facilities of any kind related thereto; and
- to make any other investments of any kind or nature including loan advances to, and acquiring shares and/or beneficial interests in, other entities,

provided that the Administrator has covenanted to use reasonable commercial efforts to ensure that we do not acquire any investment which:

- is defined as "foreign property" under any provision of the *Income Tax Act* (Canada) if such acquisition would cause the Trust Units to be foreign property under the *Income Tax Act* (Canada); or
- would result in our not being considered either a "unit trust" or a "mutual fund trust" for purposes of the *Income Tax Act* (Canada) at the time such investment was acquired.

Meetings and Resolutions of Unitholders

Meetings of Unitholders will be called at least annually. By a resolution approved at a meeting of Unitholders by more than 50% of the votes cast ("**Ordinary Resolution**") Unitholders will vote on, among other things:

- the appointment of the Trustee;
- the appointment or removal of our auditors; and
- the election or removal of the Administrator's directors.

A Special Resolution is necessary for, among other things:

- removal of the Trustee;
- amending the Trust Indenture except as described under **Amendments to the Trust Indenture**;
- subdivision or consolidation of the Trust Units unless otherwise provided for in the Trust Indenture (see **DESCRIPTION OF CAPITAL STRUCTURE Distributions**);
- sale of all or substantially all of our assets other than:
  - (i) a sale to an entity wholly-owned, directly or indirectly, by us; or
  - (ii) a sale pursuant to any enforcement or realization proceedings by any person that has been granted a security interest over all or part of our assets;
- assignment, transfer or sale of any royalty payable by any entity to us, including the POT Royalty ("**Royalty**") in whole or in part other than:
  - (i) a sale to an entity wholly-owned, directly or indirectly;
  - (ii) a sale made in conjunction with the sale of the corresponding interest in the oil and gas properties of POT to which such Royalty relates, subject to necessary approvals of the Board of Directors and Unitholders, if any, under that Royalty; or
  - (iii) a sale made pursuant to or in connection with any enforcement or realization proceedings of lenders to us or to POT upon security interests granted to them;
- termination or winding-up of our affairs; and
- appointment of an inspector to investigate the Trustee's performance.

Meetings of Unitholders shall be held in the City of Calgary or at such other place as the Trustee designates. In addition to annual meetings, the Trustee may require further meetings. Unitholders holding not less than 5% of the outstanding Trust Units or the Administrator may requisition a meeting.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. A quorum for any meeting shall be two or more persons, present in person or represented by proxy, holding in the aggregate not less than 5% of the votes attaching to all outstanding Trust Units. We will include holders of Special Voting Units for the purposes of calculating a quorum.

The Trustee

The Trust Indenture appoints Computershare Trust Company of Canada as our initial trustee. The Trustee may exercise all rights, powers and privileges that could be exercised by a beneficial owner of our assets.

The Trustee shall be reappointed or changed at every annual meeting of Unitholders and will continue to hold the office of Trustee until the Unitholders appoint a successor.

The Trustee may resign from the office on giving not less than 60 days' notice in writing. The Trustee may be removed by notice in writing delivered by the Administrator to the Trustee at any time the Trustee no longer satisfies the financial or other qualification requirements under the Trust Indenture. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee. The Trustee, the Administrator or any Unitholder may make application to a court with appropriate jurisdiction to appoint a successor trustee if one has not been put in place within certain time periods as detailed in the Trust Indenture.

The Administrator will pay the Trustee fees and reimburse the Trustee for reasonable expenses it incurs in connection with our administration. The Trustee shall have a lien on our assets with priority over the interests of the Unitholders to enforce payment of its fees and these expenses.

Delegation of Authority, Administration and Trust Governance

The Trustee may grant or delegate to the Administrator or other persons such power and authority as the Trustee may deem necessary or desirable to perform any of the duties of the Trustee. The Trustee has effectively delegated to the Administrator all significant management, administrative and governance functions pertaining to the Trust, including matters related to:

- any sale or surrender of any Royalty;
- any demand under, or sale or surrender, of any debt instruments;
- any sale or surrender of any interest that we hold in POT or in any other entity it controls, directly or indirectly;
- any acquisition or disposition of permitted investments;
- any offering of securities;
- any terms and any amendment to certain material agreements of ours;
- any underwriting agreement;
- any exercise of rights, powers and privileges relating to a response to an offer for Trust Units or for all or substantially all of our assets, or of any its subsidiaries;
- any redemption of Trust Units;
- credit facilities, borrowings, hedging, security for indebtedness (including guarantees) or other agreement to facilitate our borrowing;
- any financial statements and tax filings;
- any compliance with our legal or listing obligations;
- any calculation of distributions; and
- any meetings of Unitholders.

The Administrator may further delegate the powers and authorities that the Trustee delegated to it under the terms of the Trust Indenture.

The Trustee cannot delegate the following rights, duties and obligations:

- without limiting the duties and obligations of the Transfer Agent, the countersigning, transferring and cancelling of certificates representing Trust Units and the maintenance of registers of Unitholders;
- the payment and delivery of distributions to Unitholders;
- amending the provisions of the Trust Indenture other than making changes or corrections that legal counsel to the Trustee advises are necessary or desirable and are not materially adverse to the interests of the Unitholders or the Administrator;
- waiving the performance or breach of the provisions of the Trust Indenture;
- terminating the Trust Indenture and certain material agreements of ours; and
- indemnifying the Administrator, any entity we control directly or indirectly, and the directors, officers, employees and agents of those entities in connection with services they perform for us or the Trustee.

Limitations on Liability of the Trustee and the Administrator

The Trustee, the Administrator and their respective directors, officers, employees and agents shall not be liable to any Unitholder (in its capacity as such), in tort, contract or otherwise, in connection with any matter pertaining to us including, without limitation:

- any error in judgment;
- any action taken or suffered or omitted to be taken in good faith in reliance on either any document that is *prima facie* properly executed or any Ordinary Resolution or Special Resolution;
- any dealing with any asset that resulted in the depreciation of or loss to PET;
- any reliance on any evaluation or assessment provided by an appropriately qualified person;
- any reliance in good faith on any communication from the Administrator to the Trustee or from the Trustee to the Administrator as to any matter, fact or opinion; and
- any other action or failure to act.

The Trustee, the Administrator and any of their respective directors, officers, employees or agents remain liable for their own gross negligence, wilful misconduct or fraud. The Trust Indenture provides that, in addition to any other indemnity provided by contract or at law, the Trustee, each of its directors, officers, employees and agents and each of their respective heirs, executors, successors and assigns (collectively in this paragraph, the "**Indemnified Parties**") are to be indemnified out of our assets in respect of all liabilities, losses, costs, charges, damages, penalties and expenses (collectively in this paragraph, the "**Liabilities**") suffered or incurred in respect of any claims or proceedings that are proposed or commenced against any Indemnified Party in respect of acting as or on our behalf or the Trustee, any act, omission or error in respect of the Trust or the carrying out of any Trustee's duties or responsibilities under the Trust Indenture (including any such Liabilities relating to environmental matters and issues). However, such indemnification will not be applicable to an Indemnified Party to the extent that any of such Liabilities is suffered or incurred as a result of the Indemnified Party's own gross negligence, wilful misconduct or fraud.

The Trustee and its directors, officers, employees and agents have a lien on our assets to enforce payment of the indemnification provided to them. This lien has priority over the interests of Unitholders. The Administrator has a lien to enforce payment of the indemnification provided to it. This lien has priority over the interests of the Unitholders but will be subordinated and postponed to any security interests granted to our lenders. The indemnities to the directors, officers, employees and agents of the Administrator are unsecured obligations and do not constitute a lien on our assets. The Trustee may, however, grant a security interest in our assets to secure any such indemnity obligation to any such person if that person delivers a subordination and postponement satisfactory to our lenders.

The Trust Indenture provides that, in the exercise of the powers provided to it, the Trustee will be deemed to be acting as trustee of our assets and will not be subject to any personal liability for any liabilities or obligations against or with respect to the Trust or its assets. The Trustee will have no liability for any matters delegated to, or actions taken by, the Administrator.

The Trust Indenture does not hold the Administrator or any of its directors, officers, employees or agents or respective successors to the standard of a trustee in respect of matters delegated to the Administrator. The Trust Indenture provides that, in addition to any other indemnity provided by contract or at law, the Administrator, each of its directors, officers, employees and agents and each of their respective heirs, executors, successors and assigns (collectively in this paragraph, the "**Indemnified Parties**") are to be indemnified out of our assets in respect of all liabilities, losses, costs, charges, damages, penalties and expenses (collectively in this paragraph, the "**Liabilities**") suffered or incurred in respect of any claims or proceedings that are proposed or commenced against any Indemnified Party in respect of acting or not acting in connection with matters delegated to the Administrator, any act, omission or error in respect of the Trust or the carrying out of any of the matters delegated to the Administrator under the Trust Indenture (including any such Liabilities relating to environmental matters and issues). However, such indemnification will not be applicable to an Indemnified Party to the extent that any of such Liabilities is suffered or incurred as a result of the Indemnified Party's own gross negligence, wilful misconduct or fraud.

The Trust Indenture provides that none of the Unitholders, PET or the Trustee, in their respective capacities, shall have any right of action against the Administrator or any of the directors, officers, employees or agents of the Administrator or any of their respective heirs, executors, successors and assigns, for acts of the Administrator or any of the directors, officers, employees or agents of the Administrator, where such action is based on any allegation that the Administrator or any director, officer, employee or agent of the Administrator was a trustee for, or acting in a fiduciary capacity (or any other basis similar thereto) with respect to, the Unitholders, PET or the Trustee, in their respective capacities as such, in respect of matters delegated to the Administrator under the Trust Indenture.

The Trust Indenture provides that the Administrator will have no liability for any matters delegated by it to third persons for the actions of those third persons. The Administrator will be entitled to the indemnities provided to it in respect of that delegation and actions provided the Administrator has monitored the performance of the third party in accordance with the appropriate standard of care.

Expenses of the Administrator

We will reimburse the Administrator for reasonable expenditures and costs the Administrator incurs in our management and administration. This reimbursement is not intended to provide the Administrator, directly or indirectly, with any financial gain or loss. The Administrator has agreed that such reimbursement will be only to the extent necessary to reimburse the Administrator for actual costs incurred, including any costs of capital in respect of carrying any such costs, together with any goods and services taxes applicable thereto, until reimbursement. The Administrator has a lien on our assets to enforce payment of the costs and expenses and other amounts we must pay or reimburse to the Administrator. The Administrator's lien has priority over the interests of Unitholders, but is subordinated and postponed to any security interests granted to any lender.

Amendments to the Trust Indenture

The Trustee may amend any of the provisions of the Trust Indenture at any time, without the consent, approval or ratification of any of the Unitholders or any other person, for the purpose of:

- ensuring that we will comply with any applicable laws or requirements of any governmental agency or authority of Canada or of any province;
- ensuring that we will satisfy the provisions of each of subsections 108(2) and 132(6) of the *Income Tax Act* (Canada) as from time to time amended or replaced;
- ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;
- removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or certain material agreements of ours, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee, the Administrator and of the Unitholders are not prejudiced thereby;
- making changes for any other purpose not inconsistent with the terms of the Trust Indenture and agreements relating to any Royalty, including 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, the Administrator and of the Unitholders are not prejudiced thereby; and

- providing for the electronic delivery to the Unitholders, including Special Unitholders, of documents relating to the Trust (including annual and quarterly reports and financial statements and proxy-related materials) in accordance with applicable law from time to time.

Take-over Bids

The Trust Indenture provides that if an offeror makes a take-over bid for the Trust Units and acquires 90% or more 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) the offeror may acquire the Trust Units of Unitholders who did not accept the take-over bid, without the consent or approval of such Unitholders, on the offeror's terms under the take-over bid.

Termination of PET

PET will terminate on December 31, 2102. The Unitholders may vote by Special Resolution to terminate PET at an earlier date only if:

- holders of not less than 20% of the issued and outstanding Trust Units request in writing that PET be terminated and a quorum constituted by the holders of not less than 50% of the issued and outstanding Trust Units is present in person or by proxy at the meeting at which the Special Resolution is adopted; or
- the Trust Units have become ineligible for investment by Canadian registered retirement savings plans, registered retirement income funds, registered education savings plans and deferred profit sharing plans.

Upon the Unitholders' vote to terminate PET, the Trustee shall commence to wind-up our affairs. The Trustee will sell and convert into money, or otherwise dispose of, the Royalties and other assets in accordance with the directions, if any, of the Unitholders and the Administrator. We will not be wound-up until the Trustee has disposed of all Royalties and other investments.

The Trustee will liquidate all of our assets, satisfy or provide for our obligations and then distribute any remaining proceeds to Unitholders. Unitholders must tender their banknote form of certificates representing their Trust Units to receive their share of the proceeds. We will terminate when the Trustee has disposed of all of our assets and satisfied or provided for all of our obligations. In no event is the winding-up of our affairs to exceed ten years.

Auditors

Our auditors must be an independent recognized firm of chartered accountants with an office in Calgary, Alberta. KPMG LLP, Chartered Accountants, are presently the auditors and will hold office until the next annual meeting of Unitholders. Unitholders will appoint auditors at each successive annual meeting. The Trustee, with the approval of the Unitholders, may remove the auditors and appoint new auditors.

Reporting to Unitholders

We are subject to the continuous disclosure obligations under applicable securities legislation including the obligation to file quarterly and annual financial reports. Our year-end is December 31.

THE POT INDENTURE

The following information summarizes the material information contained in the POT Indenture.

Power and Authority of the Administrator as trustee of POT

The POT Indenture provides the Administrator, as trustee of POT, with the widest possible latitude and discretion in carrying out its rights and duties as trustee of POT, including, the power and capacity to:

- sell, transfer, assign and convey all or any part of POT's property;
- retain any investments in real or personal property which come into its possession as trustee;
- invest and reinvest any property coming into its hands as trustee in its sole discretion without being limited by any statute covering investments by trustees;
- vote any securities;
- act our absolute representative in respect of matters pertaining to the administration of the assets of POT;
- invest POT's property and assets in investments of every nature;
- borrow money from or lend money to any person on such terms and conditions as the Administrator considers appropriate;
- assume debt, and pledge, mortgage or otherwise encumber POT's properties;
- guarantee, indemnify or act as a surety or become jointly and severally liable with respect to the payment or performance of any indebtedness, liabilities or obligations of any person (including the beneficiary of POT, being PET) and to pledge, mortgage or otherwise encumber POT's properties (including all legal and beneficial interests therein) in respect of those guarantees, indemnities, suretyships or liabilities;
- join, directly or indirectly, in any syndicate, partnership or joint venture contributing all or part of the properties of POT as the contribution of POT thereto;
- explore, develop, purchase, hold, operate, market and divest petroleum, hydrocarbons, crude bitumen, oil sands, natural gas, coal bed methane, natural gas liquids, related hydrocarbons and any and all other substances producible in association therewith and related facilities and other miscellaneous interests;
- institute, prosecute, and defend any suit, action, arbitration proceeding or other proceeding affecting the Administrator or POT's properties;
- engage in rate swap transactions and derivatives for hedging purposes; and
  employ and pay any other person or persons to transact any business or to do any act of any nature in relation to POT's assets and properties.

The Administrator may resign as POT's trustee on giving not less than 30 days' written notice to us. We may remove the Administrator as trustee only on provision of a full release from liability for the Administrator and its directors, officers, employees and agents in respect of the administration of POT, except in respect of gross negligence, fraud or wilful misconduct. In addition, the Administrator shall cease to act as POT's trustee if it:

- enters into a liquidation, whether compulsory or voluntary, except a voluntary liquidation for the purpose of amalgamation or reconstruction;
- is found not to have the capacity to act as a trustee or is found to be in breach of applicable legislation governing the activities of bodies corporate as trustees; or
  is declared bankrupt or insolvent.

The Administrator is entitled to charge POT for all expenses the Administrator reasonably incurs in carrying out its duties as trustee. The Administrator will allocate such expenses and other amounts as income or capital on POT assets as it sees fit.

POT Beneficiary and PET Unitholder Limited Liability

The POT Indenture provides that no beneficiary of POT (being PET) nor any of the beneficiaries of the beneficiary (the Unitholders), in their capacity as such, will incur or be subject to any liability in connection with the assets of POT or the obligations or the affairs of POT, including acts or omissions of the Administrator. In addition, the beneficiary of POT (being PET) and its beneficiaries (being the Unitholders), in their respective capacities as such, are not contractually liable to indemnify any person for any of the above liabilities, including taxes any person may incur on behalf of POT. If, however, a court assesses any of such liabilities against us, as beneficiary of POT, or any of the Unitholders, then those liabilities will be enforceable only against and be satisfied only out of the assets of POT. POT will indemnify us, as beneficiary of POT, and the Unitholders, to the extent of POT's assets, from liability arising as a result of PET or the Unitholders not having such limited liability.

Every written contract POT enters into, unless otherwise agreed to by the Administrator, must include a provision substantially to the effect that the obligations thereunder will not be personally binding upon the Administrator, or POT's beneficiary (being PET), including its own beneficiaries, the Unitholders, in their respective capacities as such.

Notwithstanding the terms of the POT Indenture and the Trust Indenture, the beneficiary of POT (being PET) and the Unitholders, in their capacities as such, may not be protected from liabilities of POT to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against POT (to the extent that POT does not satisfy claims) including contract claims, tort claims, environmental claims, claims for taxes and certain other statutory liabilities. Unlike many other royalty trusts and income funds our structure does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to Unitholders.

Note, however, that on July 1, 2004 the *Income Trust Liability Act* (Alberta) came into force creating a statutory limitation on the liability of unitholders of Alberta income trusts such as the Trust. The legislation provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee. The implementation of the *Income Trust Liability Act* (Alberta) assists in mitigating the effect of the Trust's structure and its lack of an inter-positioned limited liability entity for claims after July 1, 2004. This legislation has not been subject to interpretation by courts in the Province of Alberta.

We will conduct POT's business so as to avoid as far as reasonably possible any material risk of liability to POT's beneficiary (being PET) and the Unitholders, in their respective capacities as such. We intend to obtain insurance where available and appropriate for the operations of POT and the Administrator, however, the amounts and types of insurance obtained may not be sufficient to provide full coverage.

Distributions of POT

POT is required to distribute all of its income for tax purposes each year to us. If any such distribution or a part thereof is contrary to any credit facility of POT, the Administrator may include in the distribution a demand subordinated, unsecured promissory note with a face amount equal to the amount of the distribution not permitted to be delivered to us. Such notes will be subordinated and postponed to liabilities to lenders of POT and to our lenders whose obligations have been guaranteed by POT.

Approval Requirements of Beneficiary

The POT Indenture provides that POT's beneficiary (PET) must approve certain matters including:

- the sale of any assets of POT to the Administrator;
- the amendment of any terms of the POT Indenture;
- certain matters relating to the Administrator; and
- the termination of POT.

Limitations of Liability of the Administrator

The POT Indenture provides the Administrator, in its capacity as POT's trustee, with similar limitations on its liability to us, as are provided in the Trust Indenture to the Administrator in connection with the powers and authorities delegated to it in the Trust Indenture. The Administrator, as trustee of POT, is also provided with indemnities similar to that provided in the Trust Indenture to the Administrator in connection with the powers and authorities delegated to it in the Trust Indenture. The POT Indenture provides that the indemnities provided under the POT Indenture are all unsecured claims and do not constitute a lien on the assets of POT. See under **THE TRUST INDENTURE Limitations on Liability of the Trustee and the Administrator** in Appendix "**A**" to this annual information form

Prohibited Amendments to POT Indenture

The POT Indenture prohibits amendments that result in any of the following:

- a change to a discretionary power of any mandatory duty imposed on the Administrator as trustee, unless the Administrator consents; or
- distributions of income or capital of POT among the beneficiaries of POT other than in accordance with the pro rata share of each such beneficiary, unless they otherwise consent.

APPENDIX B

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

Management of Paramount Energy Operating Corp., as Trustee of Paramount Operating Trust ("POT") and Administrator of Paramount Energy Trust ("PET") (collectively "PET" or "the Trust") are responsible for the preparation and disclosure of information with respect to PET'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, 2006 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

(ii) the related estimated future net revenue.

McDaniel & Associates Consultants Ltd. ("**McDaniel**") has evaluated PET's Reserves Data. The report of McDaniel is presented below.

The Reserves Committee of the board of directors of Paramount Energy Operating Corp., as Trustee of POT and Administrator of PET ("Board" or "**Board of Directors**") has:

(a) reviewed the PET's procedures for providing information to McDaniel;

(b) met with McDaniel to determine whether any restrictions affected the ability of McDaniel to report without reservation and to inquire whether there has been any disputes between McDaniel and management; and

(c) reviewed the reserves data with management and McDaniel.

The Reserves Committee of the Board of Directors has reviewed PET's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board has, on the recommendation of the Reserves Committee, approved:

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

(b) the filing of the report of McDaniel on the reserves data; and

(c) the content and filing of this report.

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

"signed by"
Susan L. Riddell Rose
President and Chief Executive Officer

"signed by"
Cameron R. Sebastian
Vice President, Finance and Chief Financial Officer

"signed by"
John W. (Jack) Peltier
Director, Chairman of the Audit Committee

"signed by"
Donald J. Nelson
Director, Chairman of the Reserves Committee

March 12, 2007

APPENDIX C

REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD. IN ACCORDANCE WITH FORM 51-101F2

January 30, 2007

Paramount Energy Trust
500, 630 – 4th Avenue S.W.
Calgary, Alberta
T2P 0J9

Attention: The Board of Directors of Paramount Energy Trust

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator
of Paramount Energy Trust (the "Company")

Dear Sir:

To the Board of Directors of Paramount Energy Trust (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2006. The reserves data consists of the following:

   (a) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs and the related estimated future net revenue; and

   (b) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using constant prices and costs and the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented 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, 2006, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

Net Present Value of Future Net Revenue ($M)
(before income taxes, 10% discount rate)

Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
January 30, 2007	Canada	-	794,622	-	794,622

5. In our opinion, the reserves data 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 report for events and circumstances occurring after the preparation date.

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

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by P. A. Welch"

P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta

Suite 2200, Bow Valley Square 3, 255-5th Avenue S.W., Calgary, Alberta T2P 3G6
Tel: (403) 262-5506 Fax: (403) 233-2744 Email: mcdaniel@mcdan.com Website: www.mcdan.com

APPENDIX D

REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD. IN ACCORDANCE WITH FORM 51-101F2

January 30, 2007

Severo Energy Corp.
500, 630 – 4th Avenue S.W.
Calgary, Alberta
T2P 0J9

Attention: The Board of Directors of Severo Energy Corp.

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator
of Paramount Energy Trust (the "Company")

Dear Sir:

To the Board of Directors of Severo Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2006. The reserves data consists of the following:

   (a) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs and the related estimated future net revenue; and

   (b) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using constant prices and costs and the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented 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, 2006, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

Net Present Value of Future Net Revenue $M
(before income taxes, 10% discount rate)

Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
January 30, 2007	Canada	-	16,345	-	16,345

5. In our opinion, the reserves data 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 report for events and circumstances occurring after the preparation date.

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

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"signed by P. A. Welch"

____

P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta

Suite 2200, Bow Valley Square 3, 255-5th Avenue S.W., Calgary, Alberta T2P 3G6
Tel: (403) 262-5506 Fax: (403) 233-2744 Email: mcdaniel@mcdan.com Website: www.mcdan.com

APPENDIX E

AUDIT COMMITTEE CHARTER

Purpose

The Audit Committee's purpose is to provide assistance to the Board in fulfilling its legal, regulatory and fiduciary obligations with respect to: financial accounting, internal control processes, continuous public disclosure, the independent audit function, non-audit services provided by Independent Auditors and such other related matters as may be delegated by the Board of Directors.

Composition, Procedures and Organization

1. The Audit Committee will be comprised of three or more Directors as determined from time to time by resolution of the Board.
2. Each member of the Audit Committee must be independent (defined on page 3-4) and as such must be free from any material relationship that may interfere with the exercise of his or her independent judgment as a member of the Audit Committee.
3. Consistent with the appointment of other Board committees, the members of the Audit Committee will be appointed by the Board at the first meeting of the Board following each AGM or at such other time as may be determined by the Board.
4. The Committee will designate the Chairman of the Audit Committee by majority vote. The presence in person or by telephone of a majority of the Audit Committee's members constitutes a quorum for any meeting.
5. All actions of the Audit Committee will require a vote of the majority of its members present at a meeting of such committee at which a quorum is present.
6. All members of the Audit Committee must be financially literate at the time of their appointment or have become financially literate within a reasonable period of time after such appointment. MI 52-110 sets out that an individual is "financially literate" if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by PET's financial statements.
7. The Board shall designate at least one Audit Committee member as the financial expert, and the member so designated must have accounting or related financial management expertise, as such qualification may be determined in the business judgment of the Board in accordance with the requirements of applicable regulatory bodies.

Accountability and Reporting

The Audit Committee is accountable to the Board. The Audit Committee must provide the Board with a summary of all meetings and its recommendations together with a copy of the minutes of each such meeting. If applicable, the Chairman will provide oral reports as requested.

All information reviewed and discussed by the Audit Committee at any meeting must be retained and made available for examination by the Board. The Audit Committee will review its mandate annually, and will forward to the Corporate Governance Committee any recommended alterations to that mandate.

Meetings

The Committee will meet with such frequency and at such intervals as it determines is necessary to carry out its duties and responsibilities.

The Audit Committee will meet to review the interim and year-end financial statements and MD&A, related financial public disclosure and regulatory filings, including continuous disclosure documentation ("Continuous Disclosure Documents") as described in MI 52-101 (which is incorporated herein by reference), and the Auditor's Report with respect to annual attestation of Internal Controls over Financial Reporting, and to report to the Board on same. In conjunction with the review of the year-end financial statements and MD&A the Audit Committee will consider the annual independent evaluation of the oil and gas reserves of PET. In addition to these scheduled meetings as contained in the Annual Board Work Schedule (Section 4 of the Manual), the Audit Committee may meet on other occasions with the Auditors in order to be advised of current practices in the industry and to discuss and review other matters including the annual work plans, processes and procedures. The Audit Committee must meet at least annually with the Auditors in the absence of PET's Officers and employees to discuss any matters that the Committee or a committee member believes should be discussed privately.

The Chairman of the Audit Committee will appoint a Director, Officer or employee of PET to act as secretary for the purposes of recording the minutes of each meeting.

Responsibilities

The Audit Committee must:

- review and recommend to the Board the appointment, termination and retention of, and the compensation to be paid to, the Auditors;
- evaluate the performance of the Auditors;
- review and consider the Auditors' integrated audit plan and annual engagement letter including the proposed fees and the proposed work plan;
- consider and make recommendations to the Board or otherwise pre-approve, all non-audit services provided by the Auditors to PET or its subsidiaries;
- oversee the work and the performance of the Auditors, review the independence of the Auditors and report to the Board on these matters;
- review the annual and quarterly financial statements, MD&A and financial press releases, and other related Continuous Disclosure Documents as appropriate, prior to their public disclosure;
- review the Auditors' report;
- provide oral or written reports to the Board when necessary;
- resolve disagreements between management and the Auditors regarding financial reporting;
- receive periodic certificates and reports from management with respect to compliance with financial, regulatory, taxation and continuous disclosure requirements, and satisfy itself (a) that adequate procedures are in place to ensure timely and full public disclosure of Continuous Disclosure Documents; and, (b) that a system of internal controls over financial reporting has been implemented and is being maintained, in accordance with both the Disclosure Policy and the Management Responsibility For Internal Control Policy;
- meet regularly with the Auditors, without management being present, at each time the interim and financial statements are being considered, to ensure that no management restrictions have been placed on the scope of the Auditors' work and to discuss the working relationship between the Auditors and management and other matters that the Audit Committee or the Auditors may wish to raise;
- review and monitor the implementation and adequacy of disclosure policies, and of internal controls over financial reporting;
- review insurance coverage including Directors' and Officers' liability insurance;
- be notified by certified mail within three business days of:
  (a) any litigation deemed likely to result in the loss of $15,000,000.00;
  (b) any regulatory investigation; or,

(c) any defalcation or embezzlement;

- review and monitor the implementation and adequacy of hedging policies and controls, with reference to the Trust's Hedging and Risk Management Policy, which is attached to this Manual in Section 7;
- review compliance with applicable regulations and policies;
- be advised of and review the results of any internal audits of PET and report on same to the Board;
- establish procedures for:

  (a) the receipt, retention and treatment of complaints received by PET regarding accounting, internal accounting controls, or accounting matters; and

  (b) the confidential, anonymous submission by employees of the issuer of concerns regarding questionable accounting or auditing matters;
- review and approve PET's hiring policies regarding partners, employees and former partners and employees of the present and former Auditor of the issuer; and
- monitor the selection and application of proper accounting principles and practices and to review the status of all relevant financial and related fiduciary aspects of PET.