PARAMOUNT
ENERGY TRUST

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2007

DATED: March 11, 2008

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ABBREVIATIONS

Natural Gas		Oil and Liquids	
Mcf	thousand cubic feet	Bbl	barrels
MMcf	million cubic feet	Mbbl	thousand barrels
Bcf	billion cubic feet	Bpd	barrels per day
Mcf/d	thousand cubic feet per day	m^3	cubic metres
MMcf/d	million cubic feet per day		
m^3	cubic metres		
MMbtu	million British Thermal Units		
GJ	gigajoule		

Approximately 99 percent of PET's annual production volumes and 98 percent of PET's proved and proved and probable reserves are related to natural gas, and as such the Trust reports production and reserves in Mcf equivalent (Mcfe). Mcfe may be misleading, particularly if used in isolation. In accordance with NI 51-101, a Mcfe conversion ratio for oil of 1 Bbl: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

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 funds 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 (“funds flow”) and funds flow per Trust Unit to analyze operating performance and financial leverage. Funds 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. Funds 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. Funds flow cannot be assured and future distributions may vary. All references to "funds flow" are based on funds flow before changes in non-cash working capital related to operating activities, certain exploration costs and settlement of asset retirement obligations. A reconciliation of funds flow to cash flow from operating activities is presented in our management’s discussion and analysis. We use the term “funds flow” as an indicator of financial performance because the term “funds 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 percent ownership of the Administrator and 100 percent ownership of the beneficial interest in POT.

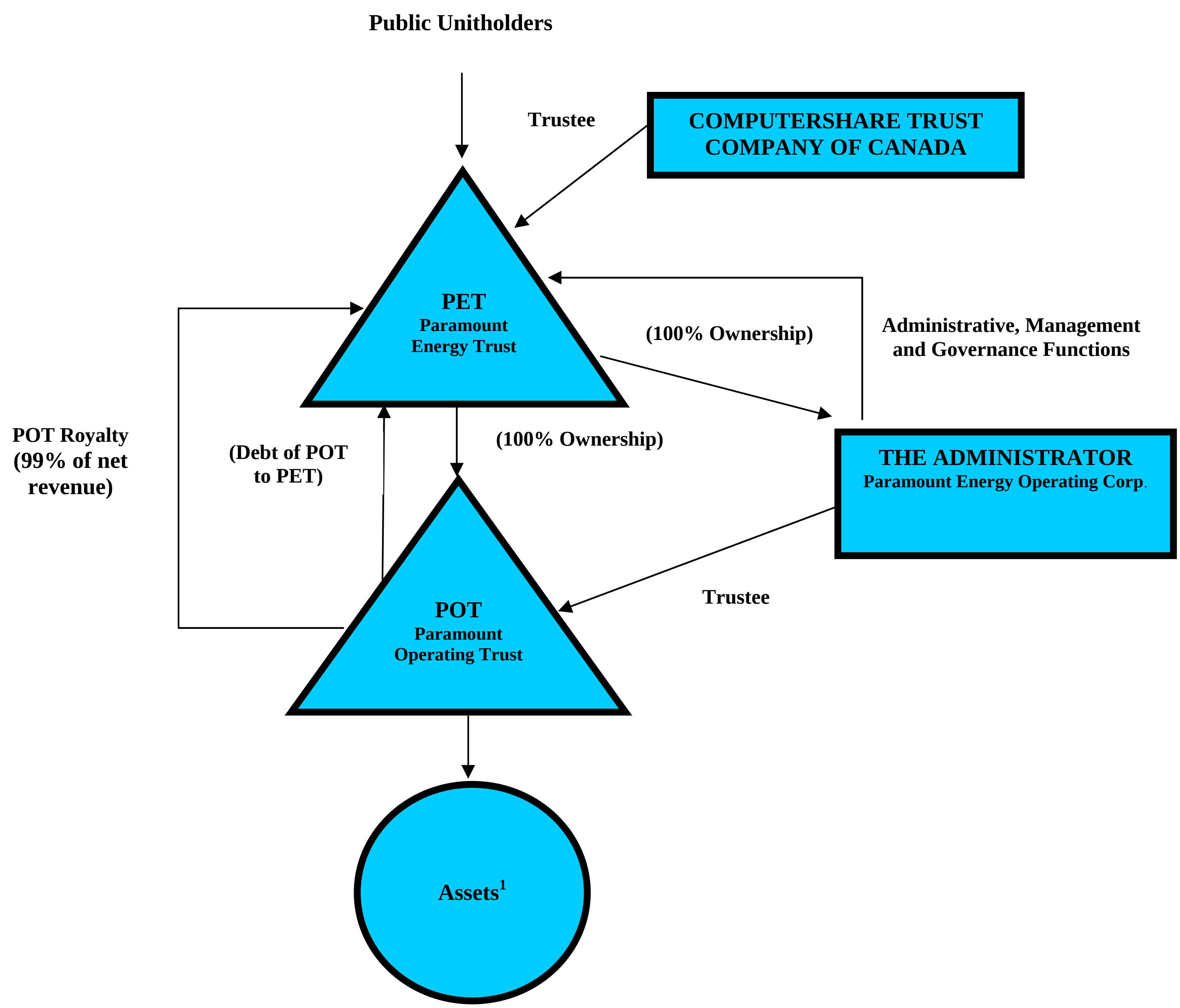
We were established for the purposes of issuing trust units ("**Trust Units**") and acquiring and holding royalties and other investments including the entire beneficial interest in POT and the POT Royalty (defined below). We effectively finance the operations of POT. We make cash distributions to holders 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 percent 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 3200, 605 – 5 Avenue S.W., Calgary, Alberta. The Administrator's registered office is located at 3200, 605 – 5 Avenue S.W., 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, 2007.

GENERAL DEVELOPMENT OF THE BUSINESS

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 percent 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 percent 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.

History and Development

The following is a description of the general development of the business of the Trust, including acquisitions, equity issues and convertible debenture financing, over its last three completed financial years.

Year Ended December 31, 2005

<u>Northeast Alberta Acquisition and Equity Financing</u>

On May 17, 2005, PET completed an 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, PET 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.

Year Ended December 31, 2006

East Central Alberta Acquisition

In February 2006, PET completed the acquisition of a private Alberta company for $92 million, adding operated, 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

PET 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 93 percent indirectly owned by PET.

Year Ended December 31, 2007

Craigend/Radway/Stry Acquisition

The Craigend/Radway/Stry acquisition closed April 30, 2007 for a purchase price of $45.2 million, and included 5 MMcf/d of shallow natural gas production as well as significant drilling and recompletion prospects and cost reduction opportunities through facility consolidation.

Birchwavy Acquisition

On June 26, 2007, PET completed a significant acquisition of natural gas producing properties in central Alberta (the "Birchwavy Acquisition") for a purchase price of $392 million. The acquired assets are technically and operationally similar to PET's base assets and offer year-round access, high working interests, operatorship and infrastructure ownership. PET has filed a Form 51-102F4 in respect of this acquisition.

Equity Issue and Convertible Debenture Financing

In conjunction with the Birchwavy Acquisition, PET completed an issue on June 20, 2007 by way of short form prospectus of 20,450,000 subscription receipts at a price of $12.25 per subscription receipt for gross proceeds of $250,512,500 and $75,000,000 aggregate principal amount of 6.50% convertible extendible unsecured subordinated debentures (the "**2007 6.50% Convertible Debentures"**) with a conversion price of $14.20 per Trust Unit.

Minor Consolidation Acquisition

PET closed a minor consolidating acquisition in northeast Alberta on June 28, 2007 for a purchase price of $14 million. This acquisition included 0.7 MMcf/d with an additional 2 MMcf/d of shut-in natural gas production for which PET receives monthly royalty credits as part of the gas over bitumen financial solution. See **REGULATORY RULINGS – GAS OVER BITUMEN.**

Trust Tax Legislation

On June 22, 2007, new legislation was passed (the "Trust Tax Legislation") pursuant to which, certain distributions will be subject to at trust-level tax, and will be characterized as dividends to the Unitholders, commencing January 1, 2011 (provided that PET only experiences "normal growth" and no "undue expansion" before then).

Once the Trust Tax Legislation becomes applicable to PET, distributions to PET's Unitholders will no longer be deductible in computing trust taxable income. In conjunction with the trust level tax, the personal tax on distributions will be similar to the tax paid on a dividend received from a taxable Canadian corporation. This will effectively reduce the income available for distribution to PET's Unitholders. with the end result being a two-tiered tax structure similar to that of corporations and the double taxation of distributions for Unitholders who hold their Trust Units in registered accounts such as RRSP, RRIF and RESP accounts.

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

On February 26, 2008, the Federal Minister of Finance announced (the "Provincial SIFT Tax Proposal") that instead of basing the provincial component of the tax on a flat rate of 13 percent, the provincial component will instead be based on the general provincial corporate income tax rate in each province in which PET has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, PET's taxable distributions will be allocated to provinces by taking half of the aggregate of:

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

- that proportion of the Trust's taxable distributions for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

Under the Provincial SIFT Tax Proposal, PET would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10 percent, which will result in an effective tax rate of 26.5 percent in 2011 and 25 percent in 2012. Taxable distributions that are not allocated to any province would instead be subject to a 10 percent rate constituting the provincial component. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

Recent Developments

On October 25, 2007, the Government of Alberta announced a "New Royalty Framework" for oil and natural gas royalties in the province of Alberta. New royalty rates will apply to all production effective January 1, 2009. While detailed Regulations have yet to be released, PET's initial assessment is that, based on the Trust's current profile of well productivity and at various natural gas prices, royalty rates would rise relative to their current levels at higher gas prices, and decrease relative to their current levels at lower gas prices.

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; Funds Flow Maximization; Accretive Acquisitions and Balance Sheet Strength – all directed towards maximization of distributions and Unitholder value.

Asset Optimization

The Trust's asset base is comprised of properties in seven core areas: West Side; East Side; Athabasca (all in northeast Alberta); Birchwavy East; Birchwavy West; East Central Alberta (all in east central and southern Alberta); and assets owned by Severo (in central Alberta). In addition, PET has certain other minor assets in 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 relatively conservative definition of acceptable risk. In addition, our significant 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 on a per unit production basis. 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.

Funds Flow Maximization

Our internal marketing group markets production from our assets with a view to optimizing gas netbacks by seeking out the best transportation arrangement and 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. A number of the office, technical and field operations staff responsible for operating and managing our current assets have done so for many 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 funds 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 and east central Alberta operating 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. 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, 2007 the Administrator had 254 full and part-time permanent employees for the purposes of operating POT's natural gas operations and rendering administrative services to PET.

Corporate 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 oil and 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.

For the 2007 financial year, PET expended approximately $2.6 million for well abandonments and $1.7 million on environmental remediation and reclamation activities including certain administrative expenses related to environmental protection initiatives. Prevent Technologies Inc., PET's safety and environmental consultant, has estimated that approximately $1.9 million will be expended for environmental remediation and reclamation activities in 2008 and PET has budgeted $5.2 million for well abandonments in 2008.

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 pose 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. Effective January 1, 2008, the AEUB was realigned into two separate regulatory bodies:

- the Energy Resources Conservation Board ("ERCB"), which regulates the oil and gas industry, and
- the Alberta Utilities Commission ("AUC"), which regulates the utilities industry.

All references to the AEUB in this Annual Information Form refer to the previous Alberta Energy and Utilities Board. All references to ERCB refer to the Energy Resources Conservation Board.

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, PET 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 percent, the deemed production is assigned the Alberta Gas Reference Price, which includes a transportation component and the entire formula is assigned an arbitrary 50 percent reduction factor.

The Trust's average net deemed production volume for purposes of the royalty adjustment was 19.9 MMcf/d for 2007. Deemed production represents all PET natural gas production shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the AEUB, 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 ten percent per year on the anniversary date of the shut-in order. Through subsequent consolidating acquisition activities in northeast Alberta, PET has increased its deemed production slightly despite the annual 10 percent decline. Current deemed production is approximately 20.0 MMcf/d.

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.

In 2007 the Trust received $17.3 million in gas over bitumen royalty adjustments, of which $3.1 million was classified as revenue and $14.2 million was recorded on the Trust's balance sheet. Cumulative royalty adjustments received to December 31, 2007 total $77.6 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 total 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 held a meeting with industry to discuss the regulatory process that should be used to deal with three applications that were before the AEUB and the possible need for a broader bitumen conservation strategy in the Peace River and Cold Lake Oil Sands Areas of Alberta. Less than 5 percent of PET's current production comes 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.

On April 4, 2006 the AEUB issued Bulletin 2006-14 announcing that it intended to conduct two separate hearings; one dealing with applications in the Cold Lake Oil Sands area, and another dealing with application in the Peace River Oil Sands Area. The AEUB rejected the suggestion by industry that an industry/AEUB collaborative approach be undertaken prior to conducting any hearings. The AEUB believed that it would be more appropriate to first reach decisions on the specific applications. The AEUB also noted that it may be appropriate to undertake an industry/AEUB collaborative approach to assess the need for a broader bitumen conservation strategy in the Peace River and Cold Lake Oil Sands Areas following decisions on the hearings. The AEUB also noted the suggestion by several parties that the AEUB work with Alberta Energy to develop a financial assistance program for any wells that may be shut in. The AEUB considers this to be an issue beyond its jurisdiction.

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. On July 24, 2007 the AEUB released Decision 2007-056 granting applications to deny production from and shut-in production from certain Clearwater natural gas wells in the Fisher and Moore areas. PET does not produce natural gas in the area identified in Decision 2007-056.

The hearing planned for the application in the Peace River Oil Sands Area was not held because the application was withdrawn. In its conclusions to Decision 2007-056 the AEUB indicated with respect to the need for broader bitumen conservation strategy in the Cold Lake and Peace River Oil Sands Areas, that since the AEUB had found it necessary to shut in gas, it believes there is a need to assess whether additional gas production should be curtailed in situations similar to those considered at the subject hearing. The specific process that should be used to conduct the assessment should be determined by the AEUB at a later time. It is possible that such a strategy, when drafted and implemented by the ERCB, will affect future natural gas production from reservoirs owned by the Trust and located within the gas over bitumen areas of concern. Decision 2007-056 did not specifically provide a timeline or process for arriving at a general bitumen conservation strategy. 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. 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.

PET's Legend area produces gas from Wabiskaw-McMurray strata within the Athabasca Oil Sands Area. This gas was deemed by the AEUB, through the regional geological study released in early 2004, to not be in communication with potentially recoverable bitumen. Oil sands activity in the area has increased through 2007 and 2008. Although the ERCB has given PET no indication that they are reconsidering the permission to produce this gas, there is a risk that oil sands operators could influence the ERCB and reopen the issue of gas production from these pools. Production from Legend is currently approximately 8.8 MMcfd, however the portion of the gas production that might be considered to be potentially at risk of further review is less than 1.5 MMcfd.

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 continues to pursue a technical solution which involves a gas storage project in the Corner/Leismer area. The shut-in McMurray gas pool is an ideal candidate for cycling methane, and discussions with the government and industry are still underway.

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 98 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 percent of the Trust's properties, the results of which are included in the McDaniel Reports, dated February 6, 2008. The effective date of the McDaniel Reports is December 31, 2007. The McDaniel Reports summarize the natural gas reserves and the net present values of future net revenue for these reserves using 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**.** 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 and probable reserves and no attempt was made to evaluate possible reserves.

The Reserves Data includes the estimated future net revenue 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 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 percent gross overriding royalty payable to the Crown. See **REGULATORY RULINGS – GAS OVER BITUMEN, RISK FACTORS** and **GOVERNMENT REGULATION**.

With the enactment of trust tax legislation (see **GENERAL DEVELOPMENT OF THE BUSINESS - *Trust Tax Legislation)*** PET is now required to present the net present values of future net revenue on an after-tax basis. The McDaniel Reports assume the utilization of PET's current existing tax pools plus additions from future development costs assumed in the McDaniel Reports, beginning in 2008 with taxation of after-tax cash flow at corporate income tax rates beginning in 2011. Actual future results will differ materially from the assumptions mandated by National Instrument 51-101.

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 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 RESERVES
TOTAL RESERVES
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORIES	Light and Medium Crude Oil		Natural Gas		Natural Gas Liquids		Natural Gas Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcfe)	Net (MMcfe)
Proved Producing	961	931	222,344	183,810	16	12	228,206	189,467
Proved Non-Producing	20	18	16,321	13,839	1	0	16,444	13,949
Proved Undeveloped	137	104	45,770	38,595	-	-	46,592	39,217
Total Proved	1,118	1,053	284,435	236,244	17	12	291,243	242,633
Total Probable	441	404	211,238	174,860	5	4	213,916	177,306
Proved and Probable	1,559	1,457	495,673	411,104	22	16	505,159	419,939

NET PRESENT VALUE[1] OF FUTURE REVENUE
BEFORE TAX
as at December 31, 2007
FORECAST PRICES AND COSTS ($millions)

	BEFORE INCOME TAXES DISCOUNTED AT (%)					
RESERVES CATEGORIES	0%	5%	10%	15%	20%	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/Mcfe)
Proved Producing	1,056	883	773	692	631	3.38
Proved Non-Producing [2]	---	9	11	11	10	0.69
Proved Undeveloped	114	79	55	38	26	1.18
Total Proved	1,170	972	839	742	667	2.88
Total Probable	767	509	362	271	211	1.69
Proved and Probable	1,938	1,481	1,201	1,012	878	2.38

NET PRESENT VALUE[1] OF FUTURE REVENUE
AFTER TAX
as at December 31, 2007
FORECAST PRICES AND COSTS ($millions)

RESERVES CATEGORIES	AFTER INCOME TAXES DISCOUNTED AT (%) 0%	5%	10%	15%	20%	UNIT VALUE AFTER INCOME TAX DISCOUNTED AT 10%/year ($/Mcfe)
Proved Producing	1,020	855	749	673	615	3.28
Proved Non-Producing [2]	(1)	9	11	11	10	0.67
Proved Undeveloped	86	59	39	26	17	0.84
Total Proved	1,106	922	800	710	641	2.75
Total Probable	614	407	291	219	173	1.36
Proved and Probable	1,720	1,329	1,090	929	814	2.16

Notes:

(1) Net present values include net revenue from oil, gas, and natural gas liquids.

(2) Negative values represent an estimate of the future abandonment costs of shut-in gas over bitumen wells.

TOTAL FUTURE NET REVENUE
TOTAL RESERVES (UNDISCOUNTED)
as of December 31, 2007
FORECAST PRICES AND COSTS ($millions)

Reserves Category	Revenue	Royalties	Gas over Bitumen Royalty Adjustments	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue After Costs Before Income Taxes	Income Taxes	Future Net Revenue after Income Taxes
Proved Reserves	**2,267**	**355**	**(89)**	**585**	**113**	**132**	**1,170**	**64**	**1,106**
Proved and Probable Reserves	**4,051**	**645**	**(89)**	**1,066**	**332**	**159**	**1,938**	**218**	**1,720**

FUTURE NET REVENUE
TOTAL RESERVES
BY PRODUCTION TYPE
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($millions)	UNIT VALUE ($/Mcf) ($/bbl)
Proved Reserves	**Natural Gas and NGL**	**813**	**2.86**
Proved Reserves	**Oil**	**26**	**23.26**
Proved Reserves - Total		**839**	
Proved and Probable Reserves	**Natural Gas and NGL**	**1,167**	**2.35**
Proved and Probable Reserves	**Oil**	**34**	**21.81**
Proved and Probable Reserves - Total		**1,201**	

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, 2007, inflation and exchange rates utilized by McDaniel in the McDaniel Reports, which were McDaniel's then current forecasts at the date of the McDaniel Reports, were as follows:

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2007
FORECAST PRICES AND COSTS

Forecast	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Natural Gas at AECO $Cdn/GJ	Foreign Exchange ($US/$Cdn) [1]
2008	90.00	89.00	6.45	1.00
2009	86.70	85.70	7.00	1.00
2010	83.20	82.20	7.00	1.00
2011	79.60	78.50	7.00	1.00
2012	78.50	77.40	7.10	1.00
2013	77.30	76.20	7.30	1.00
2014	78.80	77.70	7.55	1.00
2015	80.40	79.30	7.80	1.00
2016	82.00	80.80	8.00	1.00
2017	83.70	82.50	8.25	1.00
2018	85.30	84.10	8.45	1.00
2019	87.00	85.80	8.70	1.00
2020	88.80	87.50	8.95	1.00
2021	90.60	89.30	9.20	1.00
2022	92.40	91.10	9.40	1.00
Thereafter	+2.00%	+2.00%	+2.00%	1.00

Notes:
(3) 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, 2007 of $7.44/Mcfe for natural gas. The weighted average AECO daily gas price for the same 12 month period was $6.49/Mcfe.

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 Reports 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 and 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 and 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

As PET's oil and natural gas liquids reserves represent less than two percent of the Trust's total reserves on a natural gas equivalent basis the following reconciliations of changes in reserves are presented on a natural gas equivalent basis.

RECONCILIATION OF TRUST GROSS RESERVES
TOTAL RESERVES [1]
FORECAST PRICES AND COSTS

FACTORS	Gross Proved (Bcfe)	Gross Probable (Bcfe)	Gross Proved And Probable (Bcfe)
December 31, 2006 [2]	175.1	83.7	258.8
Improved Recoveries, Extensions and Discoveries[3]	24.1	9.8	33.9
Technical Revisions	18.2	(7.6)	10.7
Acquisitions	136.0	127.9	263.9
Dispositions	---	---	---
Production	(61.5)	-	(61.5)
Economic Factors	(0.7)	0.1	(0.6)
December 31, 2007	291.2	213.9	505.2

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, 2006 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, 2006 and 2007 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 And Probable (Bcf)
December 31, 2006(2)	142.0	66.0	208.0
Improved Recoveries, Extensions and Discoveries(3)	19.5	7.7	27.2
Technical Revisions	15.1	(6.4)	8.7
Acquisitions (net of dispositions)	117.0	110.0	227.0
Dispositions	---	---	---
Production	(50.4)	0.0	(50.4)
Economic Factors	(0.6)	0.0	(0.6)
	242.6	177.3	419.9

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, 2006 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, 2006 and 2007 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.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0
2006	0	0	0	0	4,700	4,700	0	0
2007	137	137	0	0	41,070	41,070	0	0

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0
2006	0	0	0	0	3,562	3,562	0	0
2007	35	35	0	0	90,465	90,465	0	0

The McDaniel Reports estimates that future capital costs of $331.5 million will be required over the life of PET's proved and probable reserves for the drilling, completion, equipping and tie-in of 9 conventional wells and up to 925 unconventional wells and recompletion of up to 317 wells included in our proved and probable reserves. As our technical staff continue to analyze and evaluate the asset base and expand the facilities and pipeline infrastructure, development of the Trust's undeveloped reserves will be undertaken over the next several years. In addition to opportunities on our asset base recognized in the McDaniel Reports, many of our current assets include incremental exploitation opportunities. Through the continuous refinement and analysis of PET's prospect inventory, additional opportunities are identified beyond those included in the McDaniel Reports. See "Other Oil and Gas Information – Prospect Inventory".

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 ($000's)

Year	**Proved Reserves**		**Proved And Probable Reserves**	
	0%	**10%**	**0%**	**10%**
2008	14,064	13,395	18,663	17,774
2009	31,342	27,136	37,466	33,906
2010	27,319	21,503	29,583	25,382
2011	27,571	19,728	28,475	23,112
2012	11,907	7,745	47,378	36,298
Thereafter	724	428	169,981	122,661
Total	112,927	89,934	331,546	259,133

We expect to fund future development costs from internally-generated funds 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, 2007. Production stated is our working and royalty interest share of production volumes and, unless otherwise stated, is average production for 2007. Reserve amounts stated include Trust Gross Reserves plus royalty interest reserves as at December 31, 2007 based on forecast costs and prices as evaluated in the McDaniel Reports. 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, 2007.

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 41,600 gross acres (32,174 net acres) including an average 93.4 percent working interest in 67 (62.6 net) producing natural gas wells. The average daily production for 2007 from the Chard area, including Kettle and Quigley, was approximately 5.3 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.1 Bcf and probable reserves at 1.6 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 percent PET owned gas plant at Kettle River. Two booster compressors reduce gathering system pressures to optimize production. Approximately 0.7 MMcf/d of gas flows through a third party-operated plant in which PET has a 33 percent working interest.

Cold Lake

The Cold Lake area is in northeast Alberta approximately 250 kilometres southeast of Fort McMurray. The Cold Lake area comprises 133,121 gross acres (100,295 net acres) of which 1,280 gross acres (512 net acres) are oil sands leases, including an average 73.9 percent working interest in 99 (73.2 net) producing natural gas wells. The average daily production for 2007 from the Cold Lake Area was approximately 5.2 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.9 Bcf and probable reserves at 1.6 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 percent PET owned compressor stations.

Corner/Leismer

The Corner/Leismer area is in northeast Alberta approximately 90 kilometres southwest of Fort McMurray. The area comprises 328,320 gross acres (311,979 net acres) including a 97.1 percent working interest in 79 (76.7 net) producing natural gas wells. The average daily production for 2007 from the Corner/Leismer area was approximately 5.4 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.8 Bcf and probable reserves at 1.3 Bcf of natural gas for the Corner/Leismer area. In addition, we have 17.3Bcf 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 two 100 percent PET owned field booster compressors and one gas plant 32.5 percent owned by PET.

Craigend

The Craigend area is in northeast Alberta approximately 120 miles northeast of Edmonton. The Craigend area comprises 144,360 gross acres (110,512 net acres) with an average 78.3 percent working interest in 84 (65.7net) producing natural gas wells. The average daily production for 2007 from the Craigend area was approximately 4.4 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.7 Bcf and probable reserves at 1.9 Bcf for the Craigend area. Production from the Craigend area is processed through a 50 percent owned gas plant that is operated by a third party.

Thornbury

The Thornbury area is in northeast Alberta approximately 75 kilometres southwest of Fort McMurray. The area comprises 58,240 gross acres (42,892 net acres) including an average 75.2 percent working interest in 45 (33.9net) producing natural gas wells. The average daily production for 2007 from the Thornbury area was approximately 3.6 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.6 Bcf and probable reserves at 2.3 Bcf of natural gas for the Thornbury area. In addition, we have 0.4 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 a third party.

East Side Other

The East Side Other area is in northeast Alberta, and comprises 349,478 gross acres (224,607 net acres) of which 3,840 acres (3,840 net) are oil sands leases in the Clyde area, including an average 52.6 percent working interest in 85 (46.1 net) producing natural gas wells. The average daily production for 2007 from the East Side Other area was approximately 3.1 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.1 Bcf and probable reserves at 0.8 Bcf of natural gas for the East Side Other area. In addition, we have 2.1 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the East Side Other area is processed through a combination of non-operated plants where PET has a working interest and third party owned and operated plants.

Northeast Alberta West Side

Ells

The Ells area is located in northeast Alberta approximately 70 kilometres northwest of Fort McMurray, and comprises 44,160 gross acres (40,480 net acres) of which 15,360 gross acres (15,360 net acres) are oil sands leases, as well as a 100 percent working interest in 21 producing natural gas wells. The average daily production for 2007 from the Ells area was approximately 2.7 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 2.3 Bcf and probable reserves at 0.6 Bcf of natural gas for the Ells Property. The Ells area includes related facilities including a 100 percent 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 259,840 gross acres (204,307 net acres) of which 7,680 gross acres (7,680 net acres) are oil sands leases, including an average 84.6 percent working interest in 98 (82.9 net) producing natural gas wells. The average daily production for 2007 from the Legend area was approximately 11.9 MMcf/d of natural gas. The McDaniel Report evaluated our proved reserves at 15.4 Bcf and probable reserves at 3.8 Bcf of natural gas for the Legend area. We have a 78.8 percent interest in an operated gas plant and nine field booster compressors with working interests ranging from 86.9 percent to 100 percent, 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 292,871 gross acres (252,920 net acres) of which 48,000 gross acres (48,000 net acres) are oil sands leases, including an average 95.8 percent working interest in 51 (48.1 net) producing natural gas wells. The average daily production for 2007 from the Liege Area, including South, North and East Liege, was approximately 6.3 MMcf/d of natural gas. The McDaniel Report evaluated PET's total proved reserves at 11.1 Bcf and probable reserves at 4.4 Bcf of natural gas for the Liege area. Production from the Liege area is processed through the South Liege gas plant owned 80.5 percent by PET and one East Liege field booster compressor owned 90.9 percent by PET. The North Liege production flows through a 100 percent 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 144,960 gross acres (122,157 net acres) of which 1,280 gross acres (256 net acres) are oil sands leases, including an average 81.4 percent working interest in 36 (29.3 net) producing natural gas wells. The average daily production for 2006 from the Saleski area was approximately 5.5 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 13.6 Bcf and probable reserves at 5.5 Bcf of natural gas for the Saleski area. Production at Saleski is processed through one gas plant owned 58.6 percent by PET.

Teepee Creek

The Teepee Creek area is in northeast Alberta approximately 175 kilometres west of Fort McMurray. The area comprises 23,680 gross acres (20,720 net acres) including an average 82.9 percent working interest in 19 (15.8 net) producing natural gas wells. The average daily production for 2007 from the Teepee Creek area was 1.8 MMcf/d. The McDaniel Report evaluated our total proved reserves at 0.6 Bcf and probable reserves at 0.3 Bcf of natural gas for the Teepee Creek area. Production from the Teepee Creek area is processed through a 100 percent 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 161,970 gross acres (130,965 net acres) of which 12,800 gross acres (12,800 net acres) are oil sands leases, with an average 100 percent working interest in 63 producing natural gas wells. The property was acquired May 17, 2005. The average daily production for 2007 from the Woodenhouse area was 10.0 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 10.2 Bcf and probable reserves at 4.7 Bcf for the Woodenhouse area. Current production in Woodenhouse is processed through a 100 percent PET owned and operated gas plant.

West Side Other

The West Side Other area is in northeast Alberta, and comprises 218,357 gross acres (97,307 net acres) including an average 51.7 percent working interest in 45 (20.1 net) producing natural gas wells. The average daily production for 2007 from the West Side Other area was approximately 4.3 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.9 Bcf and probable reserves at 1.6 Bcf of natural gas for the West Side Other area. In addition, we have 6.5 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the West Side Other area is processed through a combination of non-operated plants where PET has a working interest and third party plants.

Athabasca

Calling Lake

The Calling Lake area is located in northeast Alberta approximately 230 kilometres north of Edmonton and comprises 118,880 gross acres (63,868 net acres) with an average 56.3 percent working interest in 109 (61.4 net) producing natural gas wells. The average daily production for 2007 from the Calling Lake area was 8.3 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 6.8 Bcf and probable reserves at 3.6 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 197,846 gross acres (172,633 net acres) of which 59,083 gross acres (59,083 net acres) are oil sands leases, including an average 77.1 percent working interest in 98 (75.5 net) producing natural gas wells. The average daily production for 2007 from the Marten Hills area was 9.1 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 10.9 Bcfe of natural gas and probable reserves at 5.0 Bcfe 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 47,360 gross acres (47,360 net acres) with an average 100 percent working interest in 26 producing natural gas wells. The average daily production for 2007 from the Mistahae area was 3.7 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.4 Bcf and probable reserves at 1.3 Bcf for the Mistahae area. Current production in Mistahae is processed through a 100 percent PET owned and operated facility.

Mitsue

The Mitsue area is located in northeast Alberta approximately 130 kilometres north of Edmonton and comprises 28,642 gross acres (19,178.7 net acres) including an average 70.9 percent working interest in 16 (11.3 net) producing oil and natural gas wells. The average daily production for 2007 from the Mitsue area was 3.7 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.5 Bcfe of natural gas and probable reserves at 0.8 Bcfe of natural gas for the Mitsue area. The majority of the production in the Mitsue area is processed through a 100 percent PET owned facility with a small amount going into a third party facility.

Panny

The Panny area is located in northeast Alberta and comprises 68,128 gross acres (66,480 net acres) with an average 100 percent working interest in 29 producing natural gas wells. The average daily production for 2007 from the Panny area was 6.3 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 8.8 Bcfe and probable reserves at 1.6 Bcfe for the Panny area. Current production in Panny is processed through a 100 percent PET owned gas processing facility.

Peter Lake

The Peter Lake area is located in northeast Alberta and comprises 57,894 gross acres (51,712 net acres) with an average 90.3 percent working interest in 20 (18.1 net) producing natural gas wells. The average daily production for 2007 from the Peter Lake area was 7.3 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.1 Bcf and probable reserves at 1.6 Bcf for the Peter Lake area. Currently a majority of the production in Peter Lake is processed through two 100 percent PET owned and operated gas processing facilities, while a small amount goes through a 100 percent 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 125,149 gross acres (119,543 net acres) of which 19,200 gross acres (18,880 net acres) are oil sands leases, with an average 100 percent working interest in 66 producing natural gas wells. The average daily production for 2007 from the Wabasca/Hoole area was 14.4 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 20.0Bcf and probable reserves at 5.6 Bcf for the Wabasca/Hoole area. Current production in Wabasca/Hoole is processed through a combination of 100 percent owned and operated compressor stations as well as third party facilities.

Athabasca Other

The Athabasca Other area is in northeast Alberta, and comprises 370,560 gross acres (211,558 net acres), of which 23,040 gross acres (23,040 net) are oil sands leases in the Duncan area, including an average 42.7 percent working interest in 91 (33.3 net) producing natural gas wells. The average daily production for 2007 from the Athabasca Other area was approximately 4.0 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.6 Bcf and probable reserves at 1.4 Bcf of natural gas for the Athabasca area. Production from the Athabasca Other area is processed through a combination of non-operated plants where PET has a working interest and third party plants.

Birchwavy West

Killam

The Killam area comprises 93,986 gross acres (61,970 net acres) including an average 47 percent working interest in 45 (21.2 net) producing wells. The average daily production for 2007 from the Killam area was 1.2 MMcfe/d of natural gas, oil and liquids. The majority of the assets in this area were acquired through the Birchwavy Acquisition and the average daily production from the date of acquisition on June 26, 2007 from the Killam area was 2.3 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 3.7 Bcfe and probable reserves at 1.4 Bcfe. Production in Killam is processed through a small 100 percent owned and operated plant and other third party plants.

Bruce

The Bruce area comprises 332,936 gross acres (227,784 net acres) including an average 69.3 percent working interest in 166 (115.1 net) producing wells. The average daily production for 2007 from the Bruce area was 5.4 MMcfe/d of natural gas, oil and liquids. The majority of the assets in this area were acquired through the Birchwavy Acquisition and the average daily production from the date of acquisition on June 26, 2007 from the Bruce area was 10.4 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 37.1 Bcfe and probable reserves at 39.5 Bcfe. Production in Bruce is processed through a 100 percent owned and operated plant and third party plants.

Warwick

The Warwick area comprises 241,535 gross acres (154,385 net acres) including an average 69.4 percent working interest in 82 (56.9 net) producing wells. The average daily production for 2007 from the Warwick area was 5.8 MMcfe/d of natural gas, oil and liquids. The majority of the assets in this area were acquired through the Birchwavy Acquisition as well as the East Central Alberta Acquisition in early 2006, and the average daily production from the date of acquisition on June 26, 2007 from the Warwick area was 4.4 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 21.6 Bcfe and probable reserves at 23.4 Bcfe. Production in Warwick is processed through a combination of an owned and operated plant, a non-operated plant where PET has a working interest, and third party plants.

Birchwavy East

Viking Kinsella

The Viking Kinsella area comprises 161,529 gross acres (88,078 net acres) including an average 65.3 percent working interest in 116 (75.7 net) producing wells. The average daily production for 2007 from the Viking Kinsella area was 2.7 MMcf/d of natural gas and 200 Bpd of oil and natural gas liquids. The majority of the assets in this area were acquired through the Birchwavy Acquisition and the average daily production from the date of acquisition on June 26, 2007 from the Viking Kinsella area was 5.2 MMcf/d of natural gas and 386 Bpd of oil and natural gas liquids. The McDaniel Report evaluated our total proved reserves at 18.1Bcfe (928 Mbbl oil and natural gas liquids, and) and probable reserves at 6.1 Bcfe (12.5 Bcf natural gas, and 275 Mbbl oil and natural gas liquids). Production in Viking Kinsella is processed through a combination of an owned and operated plant, a non-operated plant where PET has a working interest, and third party plants.

Mannville

The Manville area comprises 140,534 gross acres (126,472 net acres) including an average 94.8 percent working interest in 108 (102.4 net) producing wells. The average daily production for 2007 from the Manville area was 5.0 MMcfe/d of natural gas, oil and liquids. The majority of the assets in this area were acquired through the Birchwavy Acquisition and the average daily production from the date of acquisition on June 26, 2007 from the Mannville area was 9.7 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 28.7 Bcfe and probable reserves at 15.6 Bcfe. Production in Manville is processed through two 100 percent owned and operated plants.

Duvernay

The Duvernay area comprises 208,280 gross acres (158,936 net acres) including an average 83.4 percent working interest in 120 (100.1 net) producing wells. The average daily production for 2007 from the Duvernay area was 9.8 MMcfe/d of natural gas, oil and liquids. The majority of the assets in this area were acquired through the Birchwavy Acquisition and the average daily production from the date of acquisition on June 26, 2007 from the Duvernay area was 18.9 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 26.6 Bcfe and probable reserves at 43.4 Bcfe. Production in Duvernay is processed through a combination of an owned and operated plant, a non-operated plant where PET has a working interest, and third party plants.

East Central Alberta

The East Central Alberta area comprises assets north of the North Saskatchewan River acquired in February of 2006. The area includes 145,718 gross acres (105,289 net acres) including an average 81.5 percent working interest in 73 (59.5 net) producing natural gas wells. The average daily production for 2007 from the east central Alberta area was 2.7 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 2.4 Bcf of natural gas and probable reserves at 2.3 Bcf of natural gas. Production in the East Central Alberta area is processed through several third party facilities.

Other Southern

The Other Southern area comprises 290,252 gross acres (203,415 net acres) including an average 50.1 percent working interest in 188 (94.3 net) producing natural gas wells. The average daily production for 2007 from the West Central Saskatchewan area was 3.8 MMcfe/d of natural gas and heavy oil. The McDaniel Report evaluated our total proved reserves at 3.5 Bcfe and probable reserves at 1.3 Bcfe. Production in Other Southern is processed through a combination of 100 percent owned facilities and several third party facilities.

Severo Energy Corp.

Big Bend/Radway

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 that were primarily lower working interest and non-operated. 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 93 percent indirectly owned by PET. The Big Bend and Radway areas are located in northeast Alberta approximately 100 kilometres north of Edmonton and comprise 240,651 gross acres (119,972 net acres) with an average 48.7 percent working interest in 89 (43.3 net) producing natural gas wells. Including certain assets acquired in the Craigend/Radway/Stry Acquisition, the average daily production for 2007 from the Big Bend/Radway area was 6.3 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.5 Bcf and probable reserves at 3.3 Bcf for the Big Bend area. Current production in Big Bend/Radway is processed through a combination of operated and third party facilities.

Prospect Inventory

The Trust has a significant number of additional exploitation, development and low exposure exploration opportunities which are not recorded in the Reserve Report as these opportunities do not meet the criteria to be booked as proved or probable reserves under NI 51-101. These prospects are at various degrees of technical refinement but are generally believed to be relatively low risk and will be pursued during 2008 and beyond through drilling, completion and tie-in activities or evaluated further with additional seismic. At the discretion of the Administrator these will be pursued as they are technically refined and as economic factors such as commodity prices, proximity to infrastructure operating costs and gas production rates permit. The spending of additional capital beyond the estimates contained in the McDaniel Reports would be intended to increase value to Unitholders through the addition of production and reserves from new pools or 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.

Conventional Assets

While the McDaniel Reports include costs and reserves for the drilling of only 13 conventional natural gas wells, we are pursuing the drilling of over 90 gross wells as part of our 2008 capital expenditure budget. Further, we have 175 additional conventional locations ready for drilling in future years including:

- 15 locations in the East Side area;
- 9 locations in the West Side area;
- 24 locations in the Athabasca area;
- 39 locations in the Birchwavy East area;
- 23 locations in the Birchwavy West area;
- 25 locations in the East Central Alberta area;
- 10 locations in the Other Southern area; and
- 30 locations in the Big Bend/Radway area (Severo)

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 200 workovers and secondary zone completions are budgeted for 2008.

Unconventional Assets

As a result of the Birchwavy Acquisition (See **GENERAL DEVELOPMENT OF THE BUSINESS – Year Ended December 31, 2007**), we have developed an inventory of unconventional opportunities, including 1,017 drilling and/or recompletion targets included in the McDaniel Reports well counts. We have also identified an additional 418 drilling locations that were not included in the McDaniel Reports, as those locations did not meet the criteria to be booked as reserves under NI 51-101.

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, 2007.

	Producing		**Non-Producing(3)(4)(5)**	
Name of Area	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Northeast Alberta East Side				
Chard/Kettle/Quigley	67	62.6	69	60.8
Cold Lake	99	73.2	69	56.8
Corner/Leismer	79	76.7	142	138.4
Craigend	84	65.7	56	44.4
Thornbury	45	33.9	27	19.2
East Side Other(6)	85	46.1	126	64.8
East Side subtotal	459	358.2	489	384.4

Name of Area	Producing Gross[(1)]	Producing Net[(2)]	Non-Producing[(3)(4)(5)] Gross[(1)]	Non-Producing[(3)(4)(5)] Net[(2)]
Northeast Alberta West Side				
Ells	21	21.00	9	8.0
Legend	98	82.9	77	54.8
Liege	51	48.9	70	63.2
Saleski	39	31.8	28	25.7
Teepee Creek	19	15.8	12	10.0
Woodenhouse	63	63.0	46	45.5
West Side Other[(7)]	45	20.1	53	30.5
West Side subtotal	336	283.5	295	237.7
Athabasca				
Calling Lake	109	61.4	80	38.2
Marten Hills	98	75.5	72	57.6
Mistahae	26	26.0	25	25.0
Mitsue	16	11.3	13	10.2
Panny	29	29.0	15	15.0
Peter Lake	20	18.1	28	27.3
Wabasca/Hoole	66	66.0	41	38.0
Athabasca Other[(8)]	91	33.3	80	39.8
Athabasca subtotal	455	320.6	354	251.1
Birchwavy West				
Killam	45	21.2	88	47.9
Bruce	166	115.1	197	136.0
Warwick	82	56.9	117	96.0
Birchwavy West subtotal	293	193.2	402	279.9
Birchwavy East				
Viking Kinsella	116	75.7	149	120.5
Mannville	108	102.4	115	111.1
Duvernay	121	101.1	131	110.8
Birchwavy East subtotal	345	279.2	395	342.4
East Central Alberta	73	59.5	110	62.2
Other Southern[(9)]	191	94.6	165	120.8

Severo Energy Corp.				
Big Bend/Radway	89	43.3	84	43.0
TOTAL	**2,241**	**1,632.1**	**2,294**	**1,721.5**

Notes:

(1) "**Gross**" refers to the number of wells, producing and non-producing, respectively, in which a working interest is held by PET. In addition PET held royalty interests in 1,125 wells at December 31, 2007.

(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 187 gross (137.6 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 Reports. There are 84 wells that are classified as service wells not included in the gross/net well count.

(5) Additionally, PET has 2107 (1583.8 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, Ryan and Caribou.

(9) **Other Southern** includes Bigoray, Cabin Creek, Highvale, Rosevar, Saskatchewan, Sedalia, Craigmyle, Medicine Hat, and Eyremore.

Acreage Information (Including for Properties with no Attributed Reserves) [5]

The following table sets out our developed and undeveloped land holdings as at December 31, 2007.

	Developed Acres		**Undeveloped Acres**[3][4]	
	Gross[1]	**Net**[2]	**Gross**[1]	**Net**[2]
Northeast Alberta East Side				
Chard/Kettle/Quigley	21,120	16,302.3	20,480	15,872
Cold Lake	96,500	71,903.2	36,621	28,392
Corner/Leismer	145,530	141,348.7	182,790	170,630
Craigend	86,545	65,620.3	57,815	44,891
Thornbury	44,800	31,755.8	13,440	11,136
East Side Other	189,440	113,097.3	160,038	111,510
East Side subtotal	583,935	440,027.6	471,184	382,432
Northeast Alberta West Side				
Ells	11,520	10,560.0	32,640	29,920
Legend	97,920	74,469.8	161,920	129,837
Liege	87,040	75,558.6	205,831	177,362
Saleski	39,200	33,949.9	105,760	88,207
Teepee Creek	5,760	17,920	4,800	15,920
Woodenhouse	80,985	65,575	80,985	65,390
West Side Other	72,044	20,458.3	159,433	63,729
West Side subtotal	394,469	298,491.6	751,369	570,365
Athabasca				
Calling Lake	85,120	43,866.7	33,760	20,001
Marten Hills	95,762	74,918.5	102,084	97,715

Mistahae	26,880	26,880.0	20,480	20,480
Mitsue	17,122	10,502.7	11,520	8,676
Panny	29,664	28,800.0	38,464	37,680
Peter Lake	25,155	21,292.0	32,739	30,420
Wabasca/Hoole	51,843	48,618.4	73,306	70,924
Athabasca other	170,880	63,521.1	199,680	148,037
Athabasca subtotal	502,426	318,399.4	512,033	433,933
Birchwavy West				
Killam	50,601	22,447.9	43,386	39,522
Bruce	226,148	149,998.2	106,788	77,786
Warwick	131,017	55,029.3	110,518	99,356
Birchwavy West subtotal	407,766	227,475.4	260,692	216,664
Birchwavy East				
Viking Kinsella	109,054	39,417.1	52,475	48,661
Mannville	105,372	93,831.9	35,162	32,640
Duvernay	151,118	108,629.7	52,475	48,661
Birchwavy East subtotal	365,544	241,8787	144,800	131,608
East Central Alberta	65,659	40,333.5	80,059	64,956
Other Southern	104,467	56,083.3	185,785	147,332
Severo Energy Corp.				
Big Bend/Radway	157,378	66,492.6	83,273	53,479.2
TOTAL	2,581,643	1,689,182.0	2,489,195	2,000,768

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 2008, 244,488.7 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 there are not any existing wells within the rights associated with those lands.

(5) We do not have any material work commitments on any of our properties.

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, 2008, 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.

2008	**Natural Gas (MMcfe/d)**
Proved	170.6
Probable	14.0
Total Proved and Probable	184.6

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:

	2007	**2007 Quarter Ended**			
	Year-End	**Dec 31**	**Sept 30**	**June 30**	**Mar 31**
Average Daily Production Volume					
Natural Gas (MMcfe/d)	170.2	190.3	193.1	155.0	141.7
Average Prices Received ($/Mcfe)	7.44	7.07	5.66	8.80	8.94
Royalties Paid ($/Mcfe)	(1.04)	(0.87)	(0.93)	(1.31)	(1.15)
Operating Costs ($/Mcfe)	(1.65)	(1.67)	(1.48)	(1.54))	(1.99)
Transportation Costs ($/Mcfe)	(0.20)	(0.20)	(0.20)	(0.21)	(0.21)
Resulting Netback ($/Mcfe)	4.55	4.33	3.05	5.74	5.59

The following table indicates our average daily production from each of PET's core areas for the year ended December 31, 2007:

Name of Area	**Production (MMcfe/d)**
Northeast Alberta East Side	
Chard/Kettle/Quigley	5.3
Cold Lake	5.2
Corner/Leismer	5.4
Craigend	4.4
Thornbury	3.6
East Side Other	3.1
East Side subtotal	27.0
Northeast Alberta West Side	
Ells	2.7
Legend	11.9
Liege	6.3
Saleski	5.5

Teepee Creek	1.8
Woodenhouse	10.0
West Side Other	4.3
West Side subtotal	42.5
Athabasca	
Calling Lake	8.3
Marten Hills	9.1
Mistahae	3.7
Mitsue	3.7
Panny	6.3
Peter Lake	7.3
Wabasca/Hoole	14.4
Athabasca Other	4.0
Athabasca subtotal	56.8
Birchwavy East	
Killam	1.2
Bruce	5.4
Warwick	5.8
Birchwavy East subtotal	12.4
Birchwavy West	
Viking Kinsella	3.9
Mannville	5.0
Duvernay	9.8
Birchwavy West subtotal	18.7
East Central Alberta	2.7
Other Southern	3.8
Severo	
Big Bend/Radway	6.3
TOTAL	170.2

Capital Expenditures

The following tables summarize capital expenditures related to our activities for the year ended December 31, 2007:

($000)	
Exploration and development expenditures	109,933
Crown and freehold land purchases	8,025
Acquisitions	450,576
Dispositions	(46,408)
Other	1,254
Total	523,380

Exploration and development expenditures for 2007 include approximately $11.0 million in exploration costs which have been expensed directly on the Trust's statement of earnings. Exploration costs include seismic expenditures and dry hole costs and are considered by PET 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, 2007:

	Gross	Net
Light and Medium Oil	0	0.0
Natural Gas	129	103.2
Service	0	0.0
Dry	8	7.2
Total	137	110.4
Success Rate (%)	94	93
Exploratory	40	37.7
Development	97	72.7
Total	137	110.4

Additional Information Concerning Abandonment and Reclamation Costs

We engage 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 $194.1 million as at December 31, 2007 based on an undiscounted total future liability of $366.2 million. As at December 31, 2007, the estimated undiscounted net salvage value of our gas plants, compressors and facilities was estimated at $118.6 million ($52.1 million discounted at 10 percent). The McDaniel Reports includes an undiscounted amount of $159.2 million ($70.0 million discounted at 10 percent) with respect to expected future well abandonment costs related specifically to our proved and probable reserves and such amount is included in the Prevent estimate described above.

Marketing and Transportation

We proactively manage our gas portfolio in order to maximize the price we obtain for our production. Our internal 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 83 percent of our gas production at AECO-based market prices. The remaining 17 percent is directed to natural gas aggregator pools.

Total financial hedge arrangements and physical sales contracts outstanding as of March 10, 2008 are as follows:

Type of Contract	PET Buys/Sells	Volumes at AECO (GJ/d) (2)	Price ($/GJ) (1)	AECO futures market price ($/GJ) (3)	Term
Financial	Sells	105,000	7.19		March 2008
Financial	Buys	(20,000)	6.95		March 2008
Physical	Sells	15,000	7.76		March 2008
Physical	Buys	(2,500)	8.63		March 2008
Period Total		**97,500**	**7.26**	**7.30**	**March 2008**
Financial – NYMEX	Sells	15,000	US $8.30		March 2008
Financial – NYMEX	Buys	(15,000)	US $8.24		March 2008
Period Total		**-**	**-**		**March 2008**
Financial	Sells	87,000	7.30		April – October 2008
Financial	Buys	(15,000)	6.91		April – October 2008
Physical	Sells	5,500	6.65		April - October 2008
Financial	Buys	(2,500)	6.56		April – October 2008
Period Total		**75,000**	**7.26**	**8.17**	**April – October 2008**
Financial – NYMEX	Sells	10,000	US $7.70		April – October 2008
Physical – NYMEX	Sells	7,500	US $7.04		April – October 2008
Period Total		**17,500**	**US $7.42**	**US $9.75**	**April – October 2008**
Physical	Sells	2,500	7.45		March – December 2008
Physical	Buys	(2,500)	6.63		March – December 2008
Period Total		**-**			**March – December 2008**
Financial	Sells	96,000	7.75		November 2008 – March 2009

Financial	Buys	(5,000)	7.26		November 2008 – March 2009
Physical	Sells	10,000	8.22		November 2008 – March 2009
Physical	Buys	(7,500)	7.70		November 2008 – March 2009
Period Total		**93,500**	**7.79**	**8.84**	**November 2008 – March 2009**
Financial – NYMEX	Sells	2,500	9.42		November 2008 – March 2009
Financial – NYMEX	Buys	(2,500)	9.26		November 2008 – March 2009
Period Total		**-**			**November 2008 – March 2009**
Financial	Sells	42,500	7.19		April – October 2009
Financial	Buys	(5,000)	7.17		April – October 2009
Period Total		**37,500**	**7.19**	**7.38**	**April – October 2009**
Financial	Sells	15,000	8.20		November 2009 – March 2010
Financial	Buys	(5,000)	8.15		November 2009 – March 2010
Period Total		**10,000**	**8.20**	**8.18**	**November 2009 – March 2010**

[1] Average price calculated using weighted average price for sell contracts.
[2] All transactions are at AECO unless identified specifically as a NYMEX transaction. NYMEX transactions are measured in $US per MMbtu/d.
[3] AECO monthly index prices have settled for March; futures market reflects AECO forward market prices as at March 10, 2008.

PET's NYMEX-based financial and physical forward gas sales arrangements as of March 10, 2008 are as follows:

Type of contract	**Volumes at NYMEX (MMbtu/d)**	**Price ($US/MMbtu)**	**Term**
Physical – basis (sell)	2,500	(1.23)	March 2008
Physical – basis (sell)	37,500	(0.97)	April – October 2008
Physical – basis (buy)	(27,500)	(1.05)	April – October 2008
Financial – basis (sell)	5,000	(0.98)	April – October 2008
Period Total	**15,000**	**(0.97)**	**April – October 2008**
Physical – basis (sell)	17,500	(0.45)	April – October 2010
Physical – basis (buy)	(15,000)	(0.72)	April – October 2010
Period Total	**2,500**	**(0.45)**	**April – October 2010**

Tax Horizon

PET, and its principal operating entity POT, are taxable entities under 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, PET does not expect to pay income taxes until the earlier of January 1, 2011 or if and when it ceases to be a trust. New legislation passed in June 2007 will impose a tax on distributions from entities, such as the Trust, beginning generally on January 1, 2011. Commencing in January 2011 (provided that the Trust experiences only "normal growth" and no "undue expansion" before then) the Trust will be liable for tax on all income payable to Unitholders, which the Trust will not be able to deduct in computing its taxable income. See **GENERAL DEVELOPMENT OF BUSINESS – Trust Tax Legislation.**

RISK FACTORS

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

Uncertainty exists with respect to our ability to produce a portion of our shut in 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.

The AEUB has also indicated that it believes there is a need to assess whether additional gas production should be curtailed in situations similar to those considered at hearings to-date and whether there is a need for a broad bitumen conservation strategy in all areas where natural gas production may interfere with eventual bitumen recovery. It is possible that such a strategy, when drafted and implemented by the ERCB (formerly AEUB), will affect future natural gas production from reservoirs owned by the Trust and located within the gas over bitumen areas of concern as 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.

While we have no significant additional production recommended for shut-in by any party or the ERCB 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.

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 and market sentiment. 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 either greater than or less 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, inaccurate geological or geophysical interpretations, 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 30 percent 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 with a current credit availability of $400 million. The revolving nature of the credit facility is set to expire on May 26, 2008 unless extended. 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.

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.

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 PET. 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 significantly 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 mitigate our exposure to commodity price risk. 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 and our Unitholders.

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 percent 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).

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.

Trust Tax Legislation

The Trust Tax Legislation results in a tax applicable at the trust level on certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and treats distributions as dividends to the Unitholders. Existing trusts will have a four-year transition period and, subject to the qualification below, the new tax will apply in January 2011. Once applied the new tax will affect PET's funds flow and may impact cash distributions from the Trust.

In light of the foregoing, the Trust Tax Legislation has reduced the value of the Trust's units, which increases the cost to PET of raising capital in the public capital markets for acquisition opportunities. PET's access to capital markets could also be affected by this legislation. In addition, the Trust Tax Legislation is 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 Trust Tax Legislation.

We may decide to modify the structure of the Trust.

Currently, PET's assets are well suited to the cash distributing model of the trust structure. However the changes in the trust tax legislation have affected our unitholder base and our access to capital. In order to maximize short term and long term value for Unitholders we may be make changes to our operations and assets as well as our capital structure. This may cause us to consider alternative structures for the Trust.

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, more strict 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 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.

Distributions to Unitholders may be subject to change without notice.

The board of directors of the Trust's Administrator meets on a monthly basis to set the distribution based on cash flow projections which incorporate PET's base production forecasts, current hedges and physical forward natural gas sales, the forward market for natural gas prices, and the Trust's capital spending program and projected production additions. Future distributions are subject to change as dictated by changes in commodity price markets, operations and future business development opportunities and may vary materially from previous distributions.

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 for each of the last three years:

For the Period Ended	Payment Date	Distribution per Trust Unit
2005		
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
2006		
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
2007		
January 31, 2007	February 15, 2007	$0.200

For the Period Ended	Payment Date	Distribution per Trust Unit
February 28, 2007	March 15, 2007	$0.140
March 31, 2007	April 16, 2007	$0.140
April 30, 2007	May 15, 2007	$0.140
May 31, 2007	June 15, 2007	$0.140
June 30, 2007	July 16, 2007	$0.140
July 31, 2007	August 15, 2007	$0.100
August 31, 2007	September 17, 2007	$0.100
September 30, 2007	October 15, 2007	$0.100
October 31, 2007	November 15, 2007	$0.100
November 30, 2007	December 17, 2007	$0.100
December 31, 2007	January 15, 2008	$0.100
2008		
January 31, 2008	February 15, 2008	$0.100
February 29, 2008	March 17, 2008	$0.100

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
2007			
January	12.99	11.45	6,386,962
February	12.98	11.25	6,089,648
March	11.49	8.40	9,120,182
April	11.33	9.16	6,202,637
May	13.18	11.00	6,134,930
June	12.30	11.34	7,639,805
July	11.70	9.01	10,869,304
August	9.28	7.50	8,117,329
September	8.39	7.22	9,143,838
October	8.22	7.30	9,826,147
November	7.46	6.17	11,897,224
December	6.75	5.70	12,324,454
2008			
January	7.30	6.13	9,531,996
February	8.25	6.75	16,043,927

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
2007			
January	101.16	101.16	15,000
February	108.00	103.00	62,000
March	101.75	101.00	151,000
April	101.50	101.00	50,000
May	104.50	101.75	172,000
June	104.50	104.00	28,000
July	106.50	101.87	138,000
August	102.00	100.02	198,000
September	101.00	100.00	192,000

Period	High	Low	Volume
October	102.00	101.00	105,000
November	101.50	98.00	43,000
December	98.75	98.75	13,800
2008			
January	100.25	100.05	77,000
February	100.00	98.50	12,000

The 2005 6.25% Convertible Debentures 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 6.25% Convertible Debentures as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2007			
January	99.99	96.52	1,421,000
February	103.64	95.51	1,598,500
	99.05	90.05	2,183,000
April	99.00	94.05	1,351,000
May	101.00	97.60	1,695,000
June	100.99	97.50	685,000
July	100.99	93.01	1,908,000
August	97.99	93.75	913,000
September	98.00	90.00	863,000
October	96.99	91.51	803,000
November	97.49	91.50	656,000
December	95.00	80.00	961,800
2008			
January	96.38	85.52	830,000
February	99.75	93.26	452,000

The 2006 6.25% Convertible Debentures 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 6.25% Convertible Debentures as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2007			
January	98.00	94.40	1,428,000
February	97.45	95.75	2,360,500
March	99.00	84.01	2,157,000
April	99.00	93.26	2,428,000
May	100.00	97.00	2,434,000
June	99.50	97.50	1,645,000
July	99.93	93.51	1,366,000
August	97.44	90.01	871,000
September	97.49	88.33	815,000
October	94.00	85.01	2,461,000
November	87.99	78.00	2,091,000
December	87.99	78.00	2,091,000
2008			
January	92.00	83.00	1,659,000
February	96.00	90.01	1,037,000

On June 20, 2007 PET issued 6.50% Convertible Debentures, which are listed and posted for trading on the TSX and trade under the symbol **PMT.DB.C**. The following sets out the price range and trading volume of the 6.50% Convertible Debentures as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2007			
June 20-30	100.00	98.05	1,133,000
July	99.74	95.01	403,400
August	97.25	92.00	1,315,000
September	94.00	88.33	408,000
October	92.99	88.53	706,000
November	93.25	84.10	1,510,000
December	86.00	73.02	885,000
2008			
January	89.89	83.01	549,000
February	92.00	87.01	8,539,000

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 percent 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 percent 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 percent 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 percent 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 percent 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 percent 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. ("PRL") 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 of the Administrator 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
Roderick P. Warters Alberta, Canada	Vice President, Geoscience and New Ventures	Vice President, Geoscience and New Ventures of the Administrator since September 4, 2007. Mr. Warters joined Petro-Canada in 1996 as their Chief Geophysicist and later held the position of Northern Exploration Manager. In 2001 he joined Burlington Resources as the Vice President of Exploration for Canada, and in 2006 held the position of Senior Vice President of Exploration for ConocoPhillips Canada. Mr. Warters has held a number of technical and management positions in other organizations including Amerada Hess and Dome Petroleum.
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. Mr. Peltier is currently a director of Bow Valley Energy Ltd., a position he has held since May 2005 and previously from 1996 through February 2002. 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); and director of Thunder Energy Ltd. (and Thunder Energy Trust) (October 1995 to May 2006). Mr. Peltier has also been a director of the following public corporations: 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.

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
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).
Robert A. Maitland[8] Alberta, Canada	Director since February 7, 2008	Mr. Maitland is a Chartered Accountant with 32 years of senior business experience, primarily in the oil and gas industry. Mr. Maitland was most recently the Vice President Finance and Chief Financial Officer of Fairquest Energy Ltd. (June 2005 to June 2007) and Fairborne Energy Ltd. (May 2002 to May 2005). He has also been the Vice President and Chief Financial Officer for Canadian Midstream Services Ltd. (April 1999 to May 2001), Summit Resources Ltd., Omega Hydrocarbons Ltd., Shiningbank Energy Income Fund, Post Energy Ltd., and Pan East Petroleum Corp. He presently serves on the board of directors of Developmental Disabilities Resources Centre and several other private companies.

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, Mr. Ward and Mr. Maitland are independent, non-employee directors.

The directors and officers of the Administrator, as a group, beneficially own or control or direct, directly or indirectly an aggregate of 21,822,240 Trust Units as of March 10, 2007 representing 19.8 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

Clayton H. Riddell is a director and executive officer of PRL. PRL is, and has been since 1992, the general partner of T.T.Y. Paramount Partnership No.5 (“TTY”), a limited partnership which is an unlisted reporting issuer in certain provinces of Canada. TTY was established in 1980 to conduct oil and gas exploration and development, but has not carried on operations since 1984 and currently has nominal assets. A cease trade order against TTY was issued by the Quebec Securities Commission in 1999 for failing to file the June 30, 1998 interim financial statements Quebec. TTY received exemptions from filing interim financial statements in Alberta, Manitoba and Ontario in 1985, 1986, and 1986 respectively. PET is advised that PRL intends to dissolve TTY in 2008. Robert A. Maitland was a director of Military International Ltd. which was cease traded on December 11, 2002 for failure to file financial statements.

Other than as disclosed above, no current director or officer or securityholder holding a sufficient number of securities of PET or Administrator to affect materially the control of PET or the Administrator has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Administrator) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director or officer or securityholder holding a sufficient number of securities of PET or the Administrator to affect materially the control of PET or the Administrator has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become 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 the director, officer or securityholder.

No current director or officer or securityholder holding a sufficient number of securities of PET or the Administrator to affect materially the control of PET or the Administrator has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) 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 10, 2008, 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 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 $571,000 in 2007 and $428,572 in 2006.

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 $142,500 in 2007 and $264,094 in 2006. In both 2006 and 2007, we incurred fees for quarterly reviews and services provided with respect to a prospectus.

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 $20,195 in 2007 and $61,698 in 2006.

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 10, 2008, the aggregate number of Trust Units that have been issued under the DRIP is 10,098,318. The aggregate number of Trust Units available for distribution under the DRIP Plan as of March 10, 2008 was 955,642. 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 percent 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 common shares of Severo Energy Corp. in 2006 by way of private placement and (ii) 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
7. the 2007 6.50% 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 funds flow within the industry.

The Government of Alberta receives royalties on production of natural resources from lands in which it owns the mineral rights. On October 25, 2007, the Government of Alberta announced a new royalty regime. The new regime will introduce new royalties for conventional oil, natural gas, oil sands and bitumen effective January 1, 2009 that are linked to price and production levels and will apply to both new and existing oil sands projects.

Currently, royalties payable pursuant to Alberta Crown petroleum and natural gas leases are ad valorem royalties, assessed on a sliding scale where the rate changes depending on production rate, density and vintage of the oil. Crown royalties currently range from a cap of 30 percent ("Old Crown Royalty" wells) to 35 percent ("New Crown Royalty" wells) in the case of conventional oil , 5 to 35 percent in the case of natural gas and from 15 to 50 percent in the case of natural gas liquids.

The new royalty formula for conventional oil production on Crown lands in Alberta will operate on a sliding rate formula containing separate elements that account for oil price and monthly well production. Royalty rates for conventional oil will range up to 50 percent, with rate caps once the price of conventional oil reaches $120 per barrel.

Under the new Alberta regime, natural gas royalties will be set by a sliding rate formula sensitive to price and production volume. New natural gas royalty rates will range from 5 to 50 percent with rate caps once the price of natural gas reaches $16.59/GJ. Royalties for natural gas liquids will be set at 40 percent for pentanes and 30 percent for butanes and propane.

The implementation of the proposed changes to the royalty regime in Alberta is subject to certain risks and uncertainties. The significant changes to the royalty regime require new legislation, changes to existing legislation and regulation and development of proprietary software to support the calculation and collection of royalties. Additionally, certain proposed changes contemplate further public and/or industry consultation. There may be modifications introduced to the proposed royalty structure prior to the implementation thereof.See **GENERAL DEVELOPMENTS OF THE BUSINESS – RECENT DEVELOPMENTS** within this annual information form.

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, 2007, which are set our in our 2007 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 percent 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 percent 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 percent 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 percent 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 percent 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 percent of the funding it requires to acquire petroleum and natural gas properties. POT will bear the remaining 1 percent 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 percent 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 percent 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 percent 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 percent of the net proceeds of the sale will, subject to the following, be allocated to us with respect to the POT Royalty, and 1 percent 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 percent 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 percent 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 percent 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 percent 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 percent 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 percent 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 percent 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 RESERVES DATA AND OTHER INFORMATION 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 are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.

McDaniel & Associates Consultants Ltd. ("**McDaniel**"), an independent qualified reserves evaluator, 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 had 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 Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

"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 11, 2008

APPENDIX C

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

McDaniel & Associates Consultants Ltd.
Oil & Gas Reservoir Evaluations

February 6, 2008

Paramount Energy Trust
3200, 605 – 5th Avenue S.W.
Calgary, Alberta
T2P 3H5

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, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs. .

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2007, and identifies the respective portions thereof that we have evaluated 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
February 6, 2008	Canada	-	1,171,720	-	1,171,270

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

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

February 6, 2008

Severo Energy Corp.
3200, 605 – 5th Avenue S.W.
Calgary, Alberta
T2P 3H5

Attention: The Board of Directors of Severo Energy Corp.

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator
of Severo Energy Corp. (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, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs. .

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2007, and identifies the respective portions thereof that we have evaluated 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
February 6, 2008	Canada	-	29,255	-	29,255

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

Executed as to our report referred to above:

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

The Audit Committee is responsible for:

- reviewing and, if appropriate, recommending to the Board the approval of the annual and interim financial statements, the associated MD&A and related financial disclosure;
- annually reviewing the Audit Committee mandate and recommending any changes to the Corporate Governance Committee;
- supplying for the purposes of this Manual, in consultation with Corporate Counsel, a list of the laws, rules and regulations that pertain to the operation of the Committee;
- engaging external Auditors as approved by PET's Unitholders;
- pre-approving non-audit permitted services including the fees and other terms related to the non-audit permitted services;
- communicating directly with the Auditors who will report directly to the Audit Committee;
- reviewing programs and policies regarding the maintenance and effectiveness of disclosure controls and internal controls over the Trust's accounting and financial reporting systems;
- reviewing insurance coverage and Directors' and Officers' liability insurance; and,
- liaising with the reserves committee ("Reserves Committee") on matters relating to reserves valuations which impact the financial statements of PET.

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 the Annual Information Form, Management Information Circular; other continuous disclosure documentation ("Continuous Disclosure Documents") as described in MI 52-101 (which is incorporated herein by reference); the Auditor's Report with respect to annual attestation of Internal Controls over Financial Reporting ("ICOFR"), 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 quarterly meetings as contained in "Planning Documents For Board and Committees" (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 quarterly 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 approve the Audit Committee Mandate annually;
- 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, Annual Information Form, Management Information Circular and other related Continuous Disclosure Documents as appropriate, prior to their public disclosure;
- oversee management's establishment and maintenance of ICOFR to provide reasonable assurance with regard to reliability of financial reporting;
- review the Auditors' report on the annual audited financial statements and related assessment of ICOFR and the Auditor's review letters on interim financial statements;
- 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; and additionally, must consider whether any identified deficiencies in internal controls are significant or are material weaknesses;
- meet 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;
- review insurance coverage including Directors' and Officers' liability insurance;
- be notified in writing within three business days of any embezzlement, litigation or regulatory investigation which, in the opinion of the Trust's management, is objectively significant. Confirmation of receipt of such notification by each member of the Audit Committee will additionally be required. Any embezzlement, litigation or regulatory investigation not reported as outlined above will be reported quarterly to the Board of Directors at the March, May, August, and November meetings immediately following the discovery of such occurrence;
- 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 laws, 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 auditing matters; and
  (b) the confidential, anonymous submission by employees of the issuer of concerns regarding questionable accounting or auditing matters; (together with (a), a "Whistleblower Process")
- ensure that PET management regularly advises employees of the existence of a Whistleblower Process;
- receive regular reports respecting complaints made under the Whistleblower Process;
- inform the Auditors of whether the Audit Committee has knowledge of any actual, suspected or alleged fraud affecting PET, including complaints regarding financial reporting and confidential submissions by employees;
- review and validate PET management's annual review of fraud risk assessment;
- 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.