PARAMOUNT
ENERGY TRUST

2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

HIGHLIGHTS

FINANCIAL AND OPERATING HIGHLIGHTS ($CDN thousands, except volume and per Trust Unit amounts)	Three months ended December 31			Year ended December 31		
	2007	**2006**	**% change**	**2007**	**2006**	**% change**
FINANCIAL						
Revenue [1][2]	**123,747**	104,166	19	**462,409**	420,846	10
Funds flow [2]	**59,622**	58,166	3	**239,100**	236,653	1
Per Trust Unit [2][3]	**0.55**	0.69	(20)	**2.44**	2.82	(13)
Cash flow provided by operating activities	**38,224**	56,693	(33)	**222,937**	228,581	(2)
Per Trust Unit [3]	**0.35**	0.67	(48)	**2.27**	2.72	(17)
Net earnings (loss)	**(4,970)**	(68,254)	(93)	**(32,859)**	(18,850)	74
Per Trust Unit [3]	**(0.05)**	(0.80)	(94)	**(0.33)**	(0.22)	50
Cash distributions	**32,756**	50,968	(36)	**145,829**	221,789	(34)
Per Trust Unit [4]	**0.30**	0.60	(50)	**1.50**	2.64	(43)
Payout ratio (%) [2]	**55.0**	87.6	(37)	**61.0**	93.7	(35)
Total assets	**1,212,707**	805,764	51	**1,212,707**	805,764	51
Net bank and other debt outstanding [5]	**335,671**	245,484	37	**335,671**	245,484	37
Convertible debentures, measured at principal amount	**236,109**	161,134	47	**236,109**	161,134	47
Total net debt [5]	**571,780**	406,618	41	**571,780**	406,618	41
Unitholders' equity	**330,935**	202,713	63	**330,935**	202,713	63
Capital expenditures						
Exploration and development	**20,270**	24,104	(16)	**117,958**	138,259	(15)
Acquisitions, net of dispositions	**(47,740)**	2,536	(1,982)	**404,168**	79,760	407
Other	**389**	456	(15)	**1,254**	1,267	(1)
Net capital expenditures	**(27,081)**	27,096	(200)	**523,380**	219,286	139
TRUST UNITS OUTSTANDING (thousands)						
End of period	**109,557**	85,186	29	**109,557**	85,186	29
Weighted average	**109,013**	84,841	28	**98,107**	83,940	17
Diluted	**109,013**	84,841	28	**98,107**	83,940	17
March 3, 2008	**110,356**			**110,356**		

FINANCIAL AND OPERATING HIGHLIGHTS CONTINUED	Three Months Ended December 31			Year Ended December 31		
	2007	2006	% change	2007	2006	% change
OPERATING						
Production						
Total (Bcfe) (6)	17.5	13.3	32	62.1	56.0	11
Average daily (MMcfe/d) (6)	190.3	144.6	32	170.2	153.4	11
Per Trust Unit (cubic feet equivalent/d/Unit) (3)	1.75	1.70	3	1.74	1.83	(5)
Gas over bitumen deemed production (MMcf/d) (7)	20.0	19.8	1	19.9	20.8	(4)
Average daily (actual and deemed – MMcfe/d) (6) (7)	210.3	164.4	28	190.1	174.2	9
Per Trust Unit (cubic feet equivalent/d/Unit) (3)	1.93	1.94	(1)	1.94	2.08	(7)
Average natural gas prices ($/Mcfe)						
Before financial hedging and physical forward sales (8)	6.19	6.59	(6)	6.44	6.61	(3)
Including financial hedging and physical forward sales (8)	7.07	7.83	(10)	7.44	7.52	(1)
RESERVES (Bcfe)						
Company interest – proved (9)	294.8	177.1	66	294.8	177.1	66
Company interest - proved and probable (9) (10) (11)	509.9	261.5	95	509.9	261.5	95
Per Trust Unit (Mcfe/Unit) (12)	4.65	3.07	51	4.65	3.07	51
Estimated present value before tax ($ millions) (11)						
Proved	972.0	675.2	44	972.0	675.2	44
Proved and probable	1,481.0	942.5	57	1,481.0	942.5	57
LAND (thousands of net acres)						
Total land holdings	3,690	2,637	40	3,690	2,637	40
Undeveloped land holdings	2,001	1,273	57	2,001	1,273	57
DRILLING (wells drilled gross/net)						
Gas	23/18.3	19/13.0	21/41	129/103.2	148/111.8	(13)/(8)
Dry	1/1.0	-	100/100	8/7.2	4/1.9	100/279
Total	24/19.3	19/13.0	26/48	137/110.4	152/113.7	(10)/((3)
Success Rate	96/95	100/100	(4)/(5)	94/93	97/98	(3)/(5)

(1) Revenue includes realized gains and losses on financial instruments.

(2) This is a non-GAAP measure; please refer to "Significant accounting policies and non-GAAP measures" included in Management's Discussion and Analysis.

(3) Based on weighted average Trust Units outstanding for the period.

(4) Based on Trust Units outstanding at each cash distribution date.

(5) Net debt is measured as at the end of the period and includes net working capital (deficiency) before short-term financial instrument assets and liabilities related to the Trust's hedging activities. Total net debt includes convertible debentures.

(6) Production amounts are based on the Trust's interest before deduction of royalties.

(7) The Trust has 28.1 MMcf/d of natural gas production shut-in or denied production pursuant to various Alberta Energy and Utilities Board ("AEUB") decision reports, corresponding shut-in orders or general bulletins or through correspondence in relation to an AEUB ID 99-1 application on or prior to July 1, 2004. Deemed production is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution during the period which is received monthly from the Alberta Crown as a reduction against other royalties payable.

(8) PET's commodity hedging strategy employs both financial forward contracts and physical natural gas delivery contracts at fixed prices or price collars. In calculating the Trust's natural gas price before financial and physical hedging, PET assumes all natural gas sales based on physical delivery fixed-price or price collar contracts during the period were instead sold at AECO daily index.

(9) As evaluated by McDaniel & Associates Consultants Ltd. in accordance with National Instrument 51-101. See "Reserves" included in Management's Discussion and Analysis.

(10) Reserves are presented on a company interest basis, including working interest and royalty interest volumes but before royalty burdens. Royalty interest volumes totaled 4.7 Bcfe on a proved and probable basis in 2007 (2006 – 2.2 Bcfe).

(11) Discounted at five percent using consultant's forecast pricing. Includes gas over bitumen royalty adjustments (2007 - $77.5 million, 2006 - $88.1 million) related to the financial solution described in Note 7 above and estimated probable gas over bitumen shut-in reserves (2007 – 27.3 Bcf and $68.7 million, 2006 – 21.6 Bcf and $53.9 million). Estimated present value amounts should not be taken to represent an estimate of fair market value.

(12) Based on Trust Units outstanding at period end.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Paramount Energy Trust's ("PET" or the "Trust") operating and financial results for the year ended December 31, 2007 as well as information and estimates concerning the Trust's future outlook based on currently available information. This discussion should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2007 and 2006, together with accompanying notes. Readers are referred to the legal advisories regarding forward-looking information contained in the "Forward Looking Information" section of this MD&A. The date of this MD&A is March 10, 2008.

Mcf equivalent (Mcfe) may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), an 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.

SIGNIFICANT ACCOUNTING POLICIES AND NON-GAAP MEASURES

Successful efforts accounting

The Trust follows the successful efforts method of accounting for its petroleum and natural gas operations. This method differs from the full cost accounting method in that exploration expenditures, including exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties as well as the cost of surrendered leases and abandoned wells are expensed rather than capitalized in the year incurred. However, to allow reported funds flow in this MD&A to be comparable to industry practice, the Trust reclassifies geological and geophysical costs as well as surrendered leases and abandonment costs from operating to investing activities in the funds flow GAAP reconciliation.

Funds flow

Management uses funds flow from operations before changes in non-cash working capital ("funds flow"), funds flow per Trust Unit and annualized funds flow to analyze operating performance and 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 provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Funds flow is reconciled to its closest GAAP measure, cash flow provided by operating activities, as follows:

Funds flow GAAP reconciliation	**For the three months ended December 31**		**For the year ended December 31**	
($ thousands, except per Trust Unit amounts)	**2007**	2006	**2007**	2006
Cash flow provided by operating activities	**38,224**	56,693	**222,937**	$ 228,581
Exploration costs [(1)]	**2,120**	1,631	**11,034**	12,431
Settlement of asset retirement obligations	**314**	472	**2,597**	3,095
Changes in non-cash operating working capital	**18,964**	(630)	**2,532**	(7,454)
Funds flow	**59,622**	58,166	**239,100**	$ 236,653
Funds flow per Trust Unit [(2)]	**0.55**	0.69	**2.44**	$ 2.82

(1) Certain exploration costs are added to funds flow in order to be more comparable to other energy trusts that use the full cost method of accounting for oil and gas activities. Exploration costs that are added to funds flow include seismic expenditures and dry hole costs and are considered by PET to be more closely related to investing activities than operating activities.

(2) Based on weighted average Trust Units outstanding for the period.

Additional significant accounting policies and non-GAAP measures are discussed elsewhere in this MD&A.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's management, as appropriate, to allow timely decisions regarding required disclosure. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of December 31, 2007 (the "Evaluation Date"), that the Trust's disclosure controls and procedures as of the Evaluation Date are effective to provide reasonable assurance that material information related to the Trust, including its consolidated subsidiaries, is made known to them by others within those entities.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls have been designed to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements together with the other financial information for external purposes in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The Trust's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision internal controls over financial reporting related to the Trust, including its consolidated subsidiaries.

The Trust's Chief Executive Officer and Chief Financial Officer are required to cause the Trust to disclose herein any change in the Trust's internal control over financial reporting that occurred during the Trust's most recent interim period that materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. During 2007, the Trust engaged external consultants to assist in assessing the Trust's design of internal controls over financial reporting. No material changes were identified in the Trust's internal control of financial reporting during the year ended December 31, 2007, that had materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

Management will complete certifications in accordance with Section 404 of the Sarbanes-Oxley Act, which will be included in PET's form 40-F filed on EDGAR in the United States.

It should be noted that a control system, including the Trust's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

CHANGES TO INTERNAL CONTROLS AND PROCEDURES FOR FINANCIAL REPORTING

There were no significant changes to PET's internal controls or other factors that could significantly affect these controls subsequent to the Evaluation Date.

CORPORATE GOVERNANCE

PET is committed to maintaining high standards of corporate governance. Each regulatory body, including the Toronto Stock Exchange, the Canadian provincial securities commissions and the Securities and Exchange Commission (whose responsibilities include implementing rules under the United States Sarbanes-Oxley Act of 2002) has a different set of rules pertaining to corporate governance. PET fully conforms to the rules of the governing bodies under which it operates and, in many cases, already complies with proposals and recommendations that have not come into force.

FOURTH QUARTER 2007 RESULTS

- Production increased 32 percent to average 190.3 MMcfe/d as compared to 144.6 MMcfe/d for the fourth quarter of 2006, primarily resulting from additional volumes from acquisitions completed in 2007.

- The Trust's realized natural gas price decreased to $7.07 per Mcfe for the three months ended December 31, 2007 from $7.83 per Mcfe for the three months ended December 31, 2006, consistent with the decrease in AECO gas prices from quarter to quarter.

- Funds flow totaled $59.6 million for the quarter or $0.55 per Trust Unit as compared to $58.2 million or $0.69 per Trust Unit in the fourth quarter of 2006, as lower realized natural gas prices in the current quarter partially offset the increase in production volumes.

- Capital spending totaled $20.3 million for the fourth quarter, including the drilling of 24 wells (19.3 net wells) primarily in east central and southern Alberta with a 95 percent net success rate.

- Distributions for the fourth quarter of 2007 totaled $0.30 per Trust Unit, paid on November 15, 2007, December 17, 2007 and January 15, 2008. PET's payout ratio, which refers to distributions measured as a percentage of funds flow, was 55.0 percent for the quarter.

- PET closed the sale of the Calgary office building that it owned and occupied in December 2007 for net proceeds of $35.0 million after realtor fees, realizing a $22.0 million gain on disposition.

- PET disposed of a minor royalty interest in the fourth quarter of 2007 for total proceeds of $8.1 million. In addition, several non-core dispositions were closed in January and February 2008 that will result in additional net proceeds of $6.4 million to the Trust, with minimal impact to production volumes.

- As a result of the building disposition and the Trust's relatively low payout ratio net bank debt at December 31, 2007 was reduced to $336 million as compared to net bank debt of $382 million at September 30, 2007.

- PET finished planning and began the execution of a $48 million 2008 winter capital program targeting 15 to 20 MMcf/d of natural gas production additions through drilling, completion, tie-in and facility projects primarily in the Trust's three core areas in northeast Alberta.

- The Trust's bank credit facility borrowing base redetermination was completed during the quarter and resulted in PET's borrowing base remaining unchanged at $400 million through May 26, 2008.

ANNUAL RESULTS

(CDN$ millions, except volumes and per Trust Unit amounts)	**2007**	2006	2005
Cash flow provided by operating activities	**$ 222.9**	$ 228.6	$ 237.3
Cash flow provided by operating activities per Trust Unit	**$ 2.27**	$ 2.72	$ 3.16
Funds flow (1)	**$ 239.1**	$ 236.7	$ 260.2
Funds flow per Trust Unit	**$ 2.44**	$ 2.82	$ 3.47
Net earnings (loss)	**$ (32.9)**	$ (18.9)	$ 61.9
Distributions	**$ 145.8**	$ 221.8	$ 205.0
Distributions per Trust Unit	**$ 1.50**	$ 2.64	$ 2.72
Payout ratio (%) (1)	**61.0**	93.7	78.8
Production (MMcfe/d) (2)			
Daily average production	**170.2**	153.4	146.0
Gas over bitumen deemed production	**19.9**	20.8	22.4
Total average daily (actual and deemed)	**190.1**	174.2	168.4
Production per Trust Unit (cubic feet equivalent/d/Unit)	**1.74**	1.83	1.94
Production per Trust Unit – actual and deemed (cubic feet equivalent/d/Unit)	**1.94**	2.08	2.25

(1) These are non-GAAP measures; please refer to "Significant Accounting Policies and Non-GAAP measures" included in this MD&A.

(2) Production amounts are based on company interest (working interest and royalties receivable) before royalties payable.

- In June 2007 PET closed a significant acquisition of predominantly natural gas producing properties in east central Alberta (the "Birchwavy Acquisition") for cash consideration of $391.8 million, plus $17.6 million in respect of working capital and acquisition costs of $3.8 million. The properties acquired ("Birchwavy Assets") are located in year round access areas within and adjacent to the Trust's core areas in southern Alberta and are an operational, geographical and strategic fit with PET's existing shallow gas operations. The properties acquired averaged daily production of approximately 44.5 MMcfe/d for the last six months of 2007, including 41.6 MMcf/d of natural gas production and 475 Bbls/d of oil and natural gas liquids production. The Birchwavy Acquisition was financed through the issuance of 20,450,000 subscription receipts which were converted into Trust Units on closing of the acquisition, at a price of $12.25 each for gross proceeds of $250.5 million and $75 million aggregate principal amount of 6.50 percent convertible extendible unsecured subordinated debentures.

- PET also completed two other producing property acquisitions in the second quarter of 2007 in order to consolidate the Trust's assets in northeast Alberta for a total cost of $59 million.

- Daily average production increased 11 percent to a record 170.2 MMcfe/d in 2007 as a result of the Birchwavy Acquisition and successful capital programs during the year. Average production from the Birchwavy Assets and other acquisitions contributed 27.0 MMcfe/d to production levels for 2007. Exploration and development capital spending of $110 million in 2007 worked to mitigate production declines on both the base and acquired assets. Further production additions from 2007 capital expenditures will continue to enhance the Trust's base production as wells drilled in the Trust's all-weather access areas in the fourth quarter of 2007 are completed, tied in and brought onstream in early 2008.

- Proved reserves increased 66 percent to 294.8 Bcfe and proved and probable reserves increased 95 percent to 509.9 Bcfe at December 31, 2007 as compared to year-end 2006. Excluding future development capital, PET realized finding, development and acquisition costs of $2.75 per Mcfe for proved reserves and $1.59 per Mcfe for proved and probable reserves in 2007. Including future development capital, finding, development and acquisition costs for 2007 totaled $3.21 per Mcfe for proved reserves and $2.53 per Mcfe for proved and probable reserves.

- PET recorded funds flow of $239.1 million or $2.44 per Trust Unit for the year as compared to $236.7 million or $2.82 per Trust Unit for 2006 as higher production levels were partially offset by higher operating, interest and general and administrative expenses. The decrease in funds flow per Trust Unit is a function of the higher number of Trust Units outstanding relating to the financing for the Birchwavy Acquisition.

- PET's average realized gas price was $7.44 per Mcfe in 2007, down one percent from $7.52 per Mcfe in 2006. PET's natural gas price before financial hedging and physical forward sales decreased three percent to $6.44 per Mcfe in 2007 from $6.61 in 2006, in line with the decrease in AECO prices for the year. The $1.00 per Mcfe increase in the Trust's realized natural gas price as compared to PET's gas price before financial hedging and physical forward sales can be attributed to fixed-price forward natural gas contracts entered into by the Trust in order to provide distribution stability for PET's Unitholders and to take advantage of periodic relative strength in the forward price curve for natural gas in 2007, despite weak spot prices in the second half of the year. As a result of price management activities, PET realized $62.5 million of additional revenue and funds flow in 2007, as compared to an additional $51.0 million of revenue realized in 2006.

- Exploration and development capital spending totaled $109.9 million in 2007, comprised of a $63 million winter capital program focused on activities in the Trust's three core areas in northeast Alberta with the remaining capital expenditures directed primarily towards PET's expanding all-season access asset base in east central Alberta. In total 137 wells were drilled (110.4 net), including 25 wells (23.9 net) on lands acquired through the Birchwavy Acquisition. Land purchases totaling $8.0 million for 2007 added 203,000 net acres to the Trust's land inventory.

OPERATIONS

Properties

PET continued to expand the geographic boundaries of its operations with the Birchwavy Acquisition in June 2007. At the same time, the key attributes of PET's asset base remained unchanged. The Trust's assets are focused geographically in northeast and east central Alberta and technically with shallow natural gas comprising 99 percent of production volumes and 98 percent of reserves. The vast majority of PET's properties feature well established, high working interest production and most are operated by PET. The Trust's production profile is predictable due to the lengthy production histories and the diversification of PET's asset base. The large number of wells and facilities means unexpected downtime at any single site does not have a material impact on overall production. Lower than average operating costs and access to markets proximal to the producing properties combine to deliver high field netbacks. PET has an extensive inventory of low cost opportunities for value creation which extends throughout the asset base and the Trust has a history of adding production through relatively modest capital expenditures to offset most of the annual natural production declines. Strategic infrastructure ownership throughout PET's asset base provides additional opportunities to add value through synergies and economies of scale.

The Trust's asset base is divided operationally into seven core areas:

- **West Side –** This area includes assets west of Alberta Highway 63 which are predominately the legacy assets discovered and developed by Paramount Resources Ltd. in the Devonian Grosmont and overlying Cretaceous McMurray and Wabiskaw formations.
- **East Side** – This region is comprised of assets east of Alberta Highway 63, including Cold Lake, and production is mainly from Cretaceous Clearwater and Grand Rapids/Colony reservoirs. The majority of the 28 MMcf/d of shut-in gas related to the gas over bitumen issue is in the Wabiskaw-McMurray formation in this core area.
- **Athabasca –** This is PET's largest core area and includes assets south and west of PET's original assets in the West Side core area. Production is from multiple stratigraphic horizons including Cretaceous clastic and Devonian carbonate reservoirs.
- **Birchwavy West** – Operations in this region expanded significantly with the Birchwavy Acquisition resulting in PET creating this core area in 2007. The operations are comprised of conventional and tight unconventional shallow natural gas assets in the Warwick, Bruce and Killiam areas of central Alberta.
- **Birchwavy East** – Production from this core area is primarily from multiple objectives in the Cretaceous Mannville zone as well as unconventional tight shallow gas from the Viking formation. Mannville and Duvernay are the largest properties in this core area and the area also includes oil-producing assets in the Viking-Kinsella area. These assets were primarily acquired through the Birchwavy Acquisition but also include assets that were obtained directly through and as a follow-up to the acquisition of a private oil and gas exploration company ("Acquireco") in 2006.
- **East Central –** This core area is comprised of conventional natural gas assets in east central Alberta acquired through the Acquireco purchase in 2006 and supplemented with additional acquisition and follow-on

exploration activity in 2007 including assets included in the Birchwavy Acquisition. East Central Alberta is separated from the Birchwavy core areas by the North Saskatchewan River.

- **Severo Energy Corp. (“Severo”) –** This private oil and gas exploration and production company is 93% owned by PET and was incorporated in August 2006 initially in order to facilitate efficient development of certain non-core, low-working interest assets acquired as part of a larger acquisition in 2005. As the Trust accounts for the operations of Severo using consolidation accounting, 100 percent of Severo’s production and reserve volumes are included with the Trust’s reported volumes.

Production

Natural gas production by core area (MMcfe/d)	2007	2006	2005
West Side	**42.5**	46.3	45.3
East Side	**27.0**	26.4	28.8
Athabasca	**56.8**	68.0	65.4
Birchwavy West [1]	**12.4**	-	-
Birchwavy East [1]	**18.7**	-	-
East Central [1] [2]	**2.7**	7.0	-
Severo	**6.3**	1.0	-
Other	**3.8**	4.7	6.5
Total	**170.2**	153.4	146.0
Deemed production [3]	**19.9**	20.8	22.4
Total actual plus deemed production	**190.1**	174.2	168.4

(1) Amounts include contribution to annual average from these areas. Production from the date of the Birchwavy Acquisition from June 26, 2007 was 21.5 MMcfe/d, 32.2 MMcfe/d, and 3.1 MMcfe/d for Birchwavy West, Birchwavy East and East Central, respectively.

(2) In 2006, the East Central core area included certain assets that were reallocated to the Birchwavy West and East core areas to more closely align with the Trust’s expanded operations in the region.

(3) Deemed production is a result of shut-in production volumes in the East Side core area. See “Gas over bitumen royalty adjustments” in this MD&A.

Production volumes increased 11 percent to 170.2 MMcfe/d in 2007 from 153.4 MMcfe/d in 2006. The increase is primarily due to the Birchwavy Acquisition and a successful 2007 winter capital program which reduced production declines in each of the three core areas in northeast Alberta. The increase in production in the southern core areas is due to the Birchwavy Acquisition completed in June 2007 and continuing development of the shallow gas assets obtained through the Acquireco acquisition in 2006.

In 2007, the five largest properties located within the Trust’s core areas accounted for 33 percent of the Trust’s production with the largest single property, Wabasca in the Athabasca core area, accounting for eight percent of the total production. By comparison, in 2006 the five largest properties represented 41 percent of PET’s total production with Wabasca representing 11 percent. This diversification of production minimizes the risk that operating problems at a specific property will materially impact the Trust.

Capital expenditures

Capital expenditures ($ thousands)	2007	2006	2005
Exploration and development expenditures [1]	**109,933**	125,638	52,214
Crown and freehold land purchases	**8,025**	12,621	7,682
Acquisitions	**450,576**	97,449	285,956
Dispositions	**(46,408)**	(17,689)	(9,285)
Other	**1,254**	1,267	1,267
Total capital expenditures	**523,380**	219,286	337,834

(1) 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 (2006 - $12.4 million). Exploration costs include seismic expenditures and dry hole costs which 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 expenditures measured $109.9 million in 2007 as compared to $125.6 million for 2006. PET completed a successful winter capital program in northeast Alberta in the first quarter of 2007, investing $63 million in new drilling, recompletion, workover and facilities optimization work primarily in the Trust’s winter-access only core areas in northeast Alberta. Capital expenditures for the remaining three quarters were concentrated on the central Alberta properties obtained through the Acquireco acquisition in 2006 and the Birchwavy Assets. The Birchwavy and Acquireco acquisitions have provided PET with a multi-year drilling inventory of low-risk shallow gas targets on all-weather access properties, which has enabled the Trust to spread its capital programs evenly throughout the year, as opposed to being highly concentrated in the winter months.

Acquisitions of $450.6 million in 2007 reflect primarily the Birchwavy Acquisition completed in June. In addition, the Trust also completed two other acquisitions during the second quarter of 2007. The acquisition of producing properties in the East Side and Athabasca areas closed on April 30, 2007 for a total purchase price of $45 million after adjustments. The acquisition consolidated PET's interests in the Athabasca and East Side core areas, added approximately 5 MMcf/d of shallow natural gas production and provided drilling and recompletion prospects as well as opportunities for cost reductions through increased facilities ownership and optimization in these areas. Approximately $20 million of the acquired assets were subsequently sold to Severo. Severo's assets and liabilities are consolidated with those of PET. On June 28, 2007 PET completed the acquisition of properties in northeast Alberta producing approximately 0.7 MMcf/d with an additional 2 MMcf/d of shut-in natural gas production, for which PET receives monthly gas over bitumen royalty credits, for a net purchase price of $14 million.

Dispositions totaled $46.4 million in 2007 as compared to $17.7 million in 2006. Dispositions in 2007 comprised the sale of the Trust's downtown Calgary office building for gross proceeds of $35.7 million and the disposition of several non-operated properties including a royalty interest in a natural gas unit which was acquired with the Birchwavy Acquisition.

The Board of Directors of Paramount Energy Operating Corp., PET's Administrator, has approved a capital expenditure budget of $108 million for 2008, including crown and freehold land purchases. A $48 million winter capital program is currently underway while the capital budget for the remainder of the year can be adjusted depending on natural gas prices, as deemed appropriate.

Drilling

	2007		2006		2005	
Wells drilled	**Gross**	**Net**	Gross	Net	Gross	Net
Gas	**129**	**103.2**	148	111.8	102	54.6
Dry	**8**	**7.2**	4	1.9	4	4.0
Total	**137**	**110.4**	152	113.7	106	58.6
Success rate (%)	**94**	**93**	97	98	96	93

PET drilled 110.4 net wells in 2007 as compared to 113.7 wells in 2006. Drilling activity in the first quarter of 2007 included 84 (66.6 net) wells spread throughout the Trust's three core areas in northeast Alberta, achieving a 91 percent net success rate. Drilling for the remainder of 2007 was concentrated in the Trust's southern core areas with 53 wells (43.8 net) drilled and a 98 percent net success rate, including 25 wells (23.9 net) on the Birchwavy Assets.

Reserves

PET's complete National Instrument 51-101 reserves disclosure as at December 31, 2007 including underlying assumptions regarding commodity prices, expenses and other factors and reconciliation of reserves on a net interest basis (working interest less royalties payable), is contained in the Trust's Annual Information Form for the year ended December 31, 2007.

The reserves data set out below (the "Reserves Data") is wholly based upon an evaluation by McDaniel and Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2007 contained in a report of McDaniel dated January 31, 2008 (the "McDaniel Report"). McDaniel's evaluation covers 100 percent of the Trust's oil and natural gas properties and reserves. The Reserves Data summarizes the oil, liquids and natural gas reserves of the Trust and the net present values of future net revenue for these reserves using McDaniel forecast prices and costs. As 98 percent of the Trust's reserves are natural gas, volumes are presented on an Mcf equivalent basis. PET reports the results of the Trust's 93 percent-owned subsidiary Severo Energy Corp. ("Severo") using consolidation accounting, and therefore the amounts shown include 100 percent of the volumes and net present values related to the reserves of Severo. Reserves are presented on a company interest basis, including royalty interests and before royalty burdens. Columns and rows in reserve and net present value tables may not add due to rounding.

Natural gas reserves as at December 31 (MMcfe)	2007	2006 [2]	2005 [2]
Proved			
Developed producing	**231,339**	163,363	182,526
Developed non-producing	**16,598**	7,072	6,890
Undeveloped	**46,843**	6,703	9,006
Total proved	**294,780**	177,139	198,422
Probable producing, non-producing and undeveloped	**187,818**	62,717	62,477
Shut-in gas over bitumen [1]	**27,308**	21,644	25,174
Total probable	**215,126**	84,361	87,651
Total proved & probable	**509,907**	261,500	286,073
Trust Units outstanding (millions)	**109.6**	85.2	82.5
Total proved & probable per Trust Unit (Mcfe/Unit)	**4.65**	3.07	3.47

(1) The McDaniel report assumes that the shut-in gas over bitumen reserves are probable but the future abandonment and reclamation liability associated with the wells is proved, that the reserves return to production after ten years of shut-in and that such production is subject to an incremental ten percent gross overriding royalty pursuant to the amended Royalty Regulation.

(2) 2006 and 2005 reserves have been amended to include PET's royalty interest reserves.

The net present values of future net revenues ("NPV") for PET's reserves, before taxes using McDaniel forecast prices and costs at zero, five and ten percent discount rates are presented in the table below.

NPV of reserves as at December 31 ($millions, forecast prices and costs discounted at 0%, 5% and 10%)			2007			2006			2005
	0%	5%	10%	0%	5%	10%	0%	5%	10%
Proved									
Developed producing	**967.5**	**806.0**	**704.1**	666.3	591.8	533.7	878.5	795.0	727.8
Developed non-producing [1]	**(0.4)**	**9.4**	**11.4**	(11.6)	(9.3)	(7.7)	(0.3)	4.0	5.7
Gas over bitumen royalty adjustments	**88.9**	**77.5**	**68.5**	103.1	88.1	76.6	133.7	115.0	100.9
Undeveloped	**114.0**	**79.1**	**55.1**	6.7	4.6	2.8	22.2	18.4	15.3
Total proved	**1,170.0**	**972.0**	**839.1**	764.5	675.2	605.4	1,034.1	932.4	849.7
Probable									
Developed and undeveloped	**655.2**	**440.3**	**317.5**	275.4	213.4	171.5	265.1	206.3	166.4
Shut-in gas over bitumen reserves [2]	**112.3**	**68.7**	**44.4**	88.5	53.9	34.1	77.7	43.9	25.8
Total probable	**767.5**	**509.0**	**361.9**	363.9	267.3	205.6	342.8	250.2	192.2
Total proved & probable	**1,937.5**	**1,481.0**	**1,201.0**	1,128.4.	942.5	811.0	1,376.9	1,182.6	1,041.9
Trust Units outstanding (millions)	**109.6**	**109.6**	**109.6**	85.2	85.2	85.2	82.5	82.5	82.5
Total proved & probable per Trust Unit ($/Unit)	**17.68**	**13.51**	**10.96**	13.24	11.06	9.52	16.69	14.33	12.63

(1) The McDaniel Report incorporates an estimate for abandonment costs for producing and non-producing wells. This may result in a net liability to PET for wells in this category.

(2) The McDaniel report assumes that the shut-in gas over bitumen reserves are probable but the future abandonment and reclamation liability associated with the wells is proved, that the reserves return to production after ten years of shut-in and that such production is subject to an incremental ten percent gross overriding royalty pursuant to the amended Royalty Regulation.

At a 10 percent discount factor, the proved producing reserves including gas over bitumen royalty adjustments comprise 64 percent of the proved and probable value while total proved reserves account for 70 percent of the proved and probable value at December 31, 2007.

With the enactment of trust tax legislation (see "Income Taxes") PET is now required to present the net present values of future net revenue on an after-tax basis. The after-tax amounts from the McDaniel report using forecast prices and costs are shown below.

After-tax net present values as at December 31, 2007 ($thousands, forecast prices and costs discounted at 0% and 10%)	Total proved		Total proved and probable	
	0%	10%	0%	10%
Net present value, before taxes	**1,170,026**	**839,120**	**1,937,507**	**1,200,975**
Income taxes	**(63,981)**	**(39,420)**	**(217,776)**	**(110,767)**
Net present value, after taxes	**1,106,045**	**799,700**	**1,719,731**	**1,090,208**

The McDaniel Report assumes the utilization of PET's current existing tax pools plus additions from future development costs, 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.

The following table sets forth a reconciliation of the changes in reserves for the year ended December 31, 2007 from the opening balance on December 31, 2006 derived from the McDaniel Reports at those dates, using McDaniel forecast prices.

Reserves reconciliation (Bcfe)	Proved	Probable	Proved & Probable
December 31, 2006	177.1	84.4	261.5
Discoveries and extensions	24.1	9.8	33.9
Technical revisions	11.4	(10.2)	1.2
Acquisitions, net of dispositions	145.0	131.0	276.0
Production	(62.1)	-	(62.1)
Economic factors	(0.7)	0.1	(0.6)
December 31, 2007	**294.8**	**215.1**	**509.9**

Finding, development and acquisition ("FD&A") costs

Under NI 51-101, the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to production. Changes in forecast FDC occur annually as a result of development activities, acquisitions and disposition activities and capital cost estimates. For continuity, PET has presented herein FD&A costs calculated both excluding and including FDC.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change in estimated future development costs during that year generally will not reflect total finding and development costs related to reserves additions for that year, due to the inexact matching of project spending and related reserve bookings across reporting periods. Consequently PET has also presented three-year average FD&A cost information.

2007 FD&A costs – company interest reserves	**Proved**	**Proved and Probable**
2007 FD&A costs excluding future development capital		
Total capital expenditures including net acquisitions - $millions (1)	$ 557.0	$ 557.0
Increase in book value of unproved properties - $millions	$ (62.0)	$ (62.0)
FD&A capital expenditures including net acquisitions- $millions	$ 495.0	$ 495.0
Reserve additions including net acquisitions – Bcfe	179.8	310.5
Finding development and acquisition cost excluding FDC - $/Mcfe	$ 2.75	$ 1.59
2007 FD&A costs including future development capital		
Total capital expenditures including net acquisitions - $millions (1)	$ 557.0	$ 557.0
Increase in book value of unproved properties - $millions	$ (62.0)	$ (62.0)
FD&A capital expenditures including net acquisitions- $millions	$ 495.0	$ 495.0
Total increase in FDC - $millions	$ 81.2	$ 291.2
Total FD&A capital including change in FDC - $millions	$ 576.2	$ 786.2
Reserve additions including net acquisitions – Bcfe	179.8	310.5
Finding development and acquisition cost including FDC - $/Mcfe	$ 3.21	$ 2.53

(1) FD&A capital expenditures exclude net proceeds on building sale of $35.0 million and expenditures on leasehold improvements and office equipment of $1.3 million during 2007.

Historic company interest proved FD&A costs ($/Mcfe)	2007	2006	2005	2004
Annual FD&A, excluding FDC	2.75	6.37	4.07	4.04
Three year average FD&A, excluding FDC	3.54			
Annual FD&A, including FDC	3.21	6.38	4.34	4.09
Three year average FD&A, including FDC	3.89			

Historic company interest proved and probable FD&A costs ($/Mcfe)	2007	2006	2005	2004
Annual FD&A, excluding FDC	1.59	7.03	3.15	3.16
Three year average FD&A, excluding FDC	2.34			
Annual FD&A, including FDC	2.53	7.08	3.41	3.21
Three year average FD&A, including FDC	3.06			

New Alberta royalty regime

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, the effect of the new royalty framework on funds flow would be approximately as shown below. Royalty rates would rise relative to their current levels at higher gas prices, and decrease relative to their current levels at lower gas prices.

			AECO Gas Price ($/GJ)		
Estimated change in royalty rate [(1)]	**$5.00**	**$6.00**	**$7.00**	**$8.00**	**$10.00**
Estimated Crown royalty rate in 2009 under current royalties	17.4%	17.4%	17.4%	17.4%	17.4%
Estimated Crown royalty rate in 2009 under revised royalties	6.8%	11.3%	15.8%	18.8%	24.9%
Increase (Decrease) in royalty rate [percentage points]	(10.6%)	(6.1%)	(1.6%)	1.4%	7.5%
Percentage increase (decrease) in royalty rate [%]	(60.6%)	(34.9%)	(9.4%)	8.0%	42.3%

(1) PET estimated average 2009 well productivity based on McDaniel Report using proved and probable reserves is 175 Mcf/d.

With respect to the future cash flow related to the reserves booked in the McDaniel Report, the declining productivity profile assumed from the "blow-down" assumption of the McDaniel Report would result in lower royalty rates in future years and increases in the future net revenue from PET's proved and probable reserves. The net present value of the Trust's reserves measured at December 31, 2007 and based on McDaniel forecast prices and costs would increase as follows under the new royalty framework.

Estimated change in NPV resulting from proposed change in Alberta royalty framework			AECO Gas Price ($/GJ)	
Discounted at 5%	**$6.00[(2)]**	**McDaniel[(1)]**	**$8.00[(2)]**	**$10.00[(2)]**
($millions)				
NPV of proved and probable reserves under current royalties at McDaniel price forecast	1,481	1,481	1,481	1,481
Increase (decrease) in NPV due to price change from McDaniel prices[(3)]	(441)	---	198	825
Increase (decrease) in net present value due to new royalty regime[(4)]	83	58	48	(37)
NPV under new royalty regime at price indicated	**1,123**	**1,539**	**1,727**	**2,269**

(1) McDaniel price forecast at January 1, 2008 is $6.45/GJ for 2008 and $7.00/GJ for 2009 and 2010. Complete disclosure of McDaniel price forecast is presented in the Trust's annual information form.
(2) AECO spot price held constant with zero inflation.
(3) Increase (decrease) in net present value of future revenue assuming current royalty framework and forecast gas price indicated as compared to the McDaniel forecast.
(4) Increase (decrease) in net present value of future revenue related to the proposed royalty framework assuming the forecast gas price indicated.

Land

Land inventory	2007 Net acres	2007 Average working interest (%)	2006 Net acres	2006 Average working interest (%)	2005 Net acres	2005 Average working interest (%)
Developed	**1,689,182**	**65.4**	1,364,086	69.5	1,407,428	74.0
Undeveloped	**2,000,768**	**80.3**	1,272,813	79.8	1,012,742	74.8
Total	**3,689,950**	**72.8**	2,636,899	74.2	2,420,170	74.4

PET's undeveloped acreage position increased by 57 percent in 2007. The 310,000 net acres of undeveloped land included with the Birchwavy Acquisition and participation in Crown land offerings to continue to build PET's opportunity inventory contributed to the higher undeveloped acreage total. PET has one of the most extensive inventories of undeveloped land in the energy trust sector relative to its production and reserves base.

Approximately 232,000 net acres of the undeveloped land included in the Birchwavy Acquisition is fee title acreage, of which 78,000 net acres are currently being leased to third parties. Fee title acreage does not expire and production from these lands will not be encumbered by crown royalties.

The Trust's undeveloped acreage in the East Side Core Area includes approximately 280,000 net acres inside the gas over bitumen area of concern. While development of this acreage is restricted in certain formations, there are numerous other prospective zones in the region. The mineral rights for leases with shut-in production are continued indefinitely under Section 8-1-h of the *Mines and Minerals Act* (Alberta) until resolution of the gas over bitumen issue. The Trust has also accumulated 289,000 net acres of Oil Sands leases in the West Side, East Side and Athabasca core areas.

PET estimates the fair value of its undeveloped acreage to be $151 million at December 31, 2007 (December 31, 2006 - $86 million), using a combination of average land sale values by area and recent land sale acquisitions by the Trust.

Net Asset Value

The following net asset value ("NAV") table shows what is normally referred to as a "produce-out" NAV calculation under which the current value of the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of PET Units. PET runs its business on a going-concern basis, investing in opportunities to add value, improve profitability and increase reserves which enhance the Trust's NAV beyond the amounts shown in its annual reserve evaluation.

Net Asset Value at December 31, 2007 (1)	Undiscounted	Discounted at 5%	Discounted at 8%	Discounted at 10%
($millions except as noted)				
Total proved and probable reserves (2)	1,937.5	1,481.0	1,298.9	1,201.0
Increment for current gas prices (3)	142.7	132.5	127.2	123.5
Undeveloped land (4)	150.7	150.7	150.7	150.7
Effect of new Alberta royalty regime(5)	77.1	58.0	50.0	44.9
Net bank debt	(335.7)	(335.7)	(335.7)	(335.7)
Convertible debentures	(236.1)	(236.1)	(236.1)	(236.1)
Net asset value	1,736.2	1,250.4	1,055.0	948.3
Trust Units outstanding (millions) – basic	109.6	109.6	109.6	109.6
Net asset value per Trust Unit ($/Unit)	$15.84	$11.41	$9.63	$8.65

(1) Financial information is per PET's 2007 consolidated financial statements.
(2) Reserve values per McDaniel Report as at December 31, 2007.
(3) The average AECO gas price assumed in the McDaniel Report averaged $6.72 per GJ for 2008 and 2009. At February 28, 2008 the forward market for AECO natural gas averaged $7.82 per GJ for 2008, 2009 and 2010. An increment for the higher forward prices has been included in this net asset value calculation.
(4) Internal estimate.
(5) See "New Alberta Royalty Regime" above.

In the absence of adding reserves to the Trust, the NAV per Trust Unit will decline as the reserves are produced out. The cash flow generated by the production relates directly to the cash distributions paid to Unitholders. The above evaluation includes future capital expenditure expectations required to bring undeveloped reserves recognized by McDaniel that meet the criteria for booking under NI 51-101 on production. The above evaluation does not consider those opportunities in the Trust's extensive prospect inventory that are not captured in the NI 51-101 evaluation.

In order to determine the "going concern" value of the Trust, a more detailed independent assessment would be required of the upside potential of specific properties and the ability of the PET team to continue to make value-adding capital expenditures. At inception of the Trust in February 2003, based on the value of year-end 2002 reserves discounted at 5 percent the NAV was determined to be $8.91 per Trust Unit. Since that time, including the December 2007 distribution paid on January 15, 2008, the Trust has distributed $11.92 per Trust Unit. Despite having distributed $3.01 per Trust Unit more in cash distributions than the initial NAV, the NAV as at December 31, 2007 increased to $11.41 per Trust Unit using a 5 percent discount rate.

MARKETING

Natural gas prices

Natural gas price ($/Mcfe, except percentages)	2007	2006	2005
Reference prices			
AECO Monthly Index	**$ 6.61**	$ 6.99	$ 8.50
AECO Daily Index	**$ 6.49**	$ 6.53	$ 8.74
Alberta Gas Reference Price (1)	**$ 6.21**	$ 6.74	$ 8.30
Average PET prices			
Before financial hedging and physical forward sales (2)	**$ 6.44**	$ 6.61	$ 8.71
Percent of AECO Monthly Index	**97**	95	103
Before financial hedging (3)	**$ 6.64**	$ 7.17	$ 8.30
Percent of AECO Monthly Index	**100**	103	98
Including financial hedging and physical forward sales (“Realized” natural gas price)	**$ 7.44**	$ 7.52	$ 7.97
Percent of AECO Monthly Index	**113**	108	94

(1) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.

(2) PET’s commodity hedging strategy employs both financial forward contracts and physical natural gas delivery contracts at fixed prices or price collars. In calculating the Trust’s natural gas price before financial and physical hedging, PET assumes all natural gas sales based on physical delivery fixed-price or price collar contracts during the period were instead sold at AECO daily index.

(3) Natural gas price before financial hedging includes physical forward sales contracts for which delivery was made during the reporting period but excludes realized gains and losses on financial instruments.

U.S. natural gas prices are typically referenced to NYMEX at the Henry Hub, Louisiana while western Canada natural gas prices are referenced to the AECO Hub in Alberta. AECO Monthly Index prices decreased five percent to average $6.61 per Mcf in 2007 as compared to $6.99 per Mcf for 2006, while AECO Daily Index prices decreased one percent year over year. The declines were driven by continued high natural gas storage levels, significant strengthening of the Canadian dollar relative to the U.S. dollar in 2007, increased liquefied natural gas (“LNG”) shipments to North America and strong supply from U.S. onshore drilling. Natural gas prices continue to be highly volatile, largely around uncertainty regarding weather and its effect on natural gas demand and storage and the global factors influencing LNG shipments to North America.

The Alberta Gas Reference Price is the monthly weighted average of intra-Alberta consumers' prices and ex-Alberta border prices, reduced by allowances for transporting and marketing gas, and is used to calculate Alberta Gas Crown Royalties. The Alberta Gas Reference Price decreased nine percent from $6.74 per Mcf in 2006 to $6.21 per Mcf in 2007, consistent with the decrease in AECO monthly and daily index prices.

PET’s average realized gas price was $7.44 per Mcfe in 2007, down one percent from $7.52 per Mcfe in 2006. PET’s natural gas price before financial hedging and physical forward sales decreased three percent to $6.44 per Mcfe in 2007 from $6.61 per Mcfe in 2006, in line with the decrease in AECO prices for the year. The $1.00 per Mcfe increase in the Trust’s realized natural gas price as compared to PET’s gas price before financial hedging and physical forward sales can be attributed to fixed-price forward natural gas contracts entered into by the Trust in 2007 as part of PET’s price management strategy. As a result of price management activities, PET realized $62.5 million of additional revenue and funds flow in 2007.

Hedging and risk management

PET’s risk management strategy is focused on using financial instruments to mitigate the effect of commodity price volatility on funds flow and distributions, to lock in attractive economics on acquisitions and to take advantage of perceived anomalies in natural gas markets. The Trust maintains a balanced gas price risk management portfolio using both financial hedge arrangements and physical forward sales to hedge up to a maximum of 50 percent of forecast production including gas over bitumen deemed volumes. PET will also enter into foreign exchange swaps and physical or financial swaps related to the differential between natural gas prices at the AECO and NYMEX trading hubs in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Trust's realized gas price. The term "financial instruments" includes all financial and physical risk management contracts. Although PET considers the majority of these risk management contracts to be effective economic hedges against potential gas price volatility, the Trust does not follow hedge accounting for its financial instruments.

PET's hedging activities are conducted by an internal Risk Management Committee under guidelines approved by the administrator's Board of Directors. PET's hedging strategy though designed to protect funds flow and distributions is opportunistic in nature; depending on management's perceived position in the commodity price cycle the Trust may elect to reduce or increase its hedging position. The Trust mitigates credit risk by entering into risk management contracts with financially sound, credit-worthy counterparties.

For a complete list of PET's outstanding financial instruments as at December 31, 2007, please see note 12 to the annual consolidated financial statements as at and for the year ended December 31, 2007. PET continued to supplement its risk management program after the end of the year. Financial and physical natural gas forward sales arrangements at March 10, 2008 are as follows.

Financial hedges and physical forward sales contracts at March 10, 2008

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.

In addition to the fixed price contracts above, PET has entered into a costless financial collar to sell 5,000 GJ/d for the November 2008 through March 2009 term at a floor price of $7.00 per GJ and a ceiling price of $8.00 per GJ.

During 2007 PET terminated certain financial natural gas forward sales contracts and foreign exchange contracts in exchange for cash settlements from the Trust's counterparties totaling $32.0 million. This amount has been included in realized gains on financial instruments, net earnings and funds flow for the period.

As at March 10, 2008 the Trust has also entered into financial and forward physical gas sales arrangements to fix the basis differential between the NYMEX and AECO trading hubs as follows. The price at which these contracts settle is equal to the NYMEX index less a fixed basis amount.

Type of contract	Volumes at NYMEX (MMbtu/d)	Price (US$/MMbtu)	Term
Physical – basis (sell)	2,500	(1.23)	March 2008
Period Total	**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**

FINANCIAL RESULTS

Revenue

Revenue ($ thousands)	**2007**	2006	2005
Oil and natural gas revenue, before hedging	**412,571**	401,635	442,505
Realized gains/losses on financial instruments [1]	**49,838**	19,211	(17,764)
Natural gas revenues, after financial hedging	**462,409**	420,846	424,741

(1) Realized gains/losses on financial instruments include settlement of financial forward contracts and options for natural gas and foreign exchange.

Oil and natural gas revenue in 2007 was $462.4 million, representing a ten percent increase from $420.8 million in 2006. The increase in revenue was a function of the 11 percent increase in production volumes in 2007 as compared to the prior year and hedging gains that reduced the impact of the three percent drop in average AECO prices year over year.

The Trust recorded unrealized losses on financial instruments of $35.4 million in 2007, reflecting the change in the fair value of unsettled financial and physical forward natural gas and foreign exchange contracts during the year (see "Change in Accounting Policy" in this MD&A).

Operating netbacks

The components of operating netbacks are shown below:

Netback ($ per Mcfe)	**2007**	2006	2005
Realized gas price	**$ 7.44**	$ 7.52	$ 7.97
Royalties	**(1.04)**	(1.18)	(1.66)
Operating costs	**(1.65)**	(1.50)	(1.20)
Transportation costs	**(0.20)**	(0.21)	(0.26)
Netback	**$ 4.55**	$ 4.63	$ 4.85

Royalties

PET pays Crown, freehold and gross overriding royalties that are dependent upon production volumes, commodity prices, location and age of producing wells and type of production. Gas Crown royalties are reduced by Gas Cost Allowance ("GCA") deductions. The GCA deductions are based on processing fees and allowable capital costs incurred at a property and are in accordance with Crown royalty regulations. Royalty income received is included in revenue. The effective royalty rate applicable to the Trust in 2007 was 14.0 percent (2006 – 15.7 percent) or $1.04 per Mcfe (2006 - $1.18 per Mcfe). The decrease in royalty rate was primarily due to the nine percent decline in the Alberta Gas Reference Price from year to year, as compared to a one percent decrease in the Trust's realized natural gas price. The increase in the Trust's royalty interest production and revenues, which do not incur corresponding royalty expense, as a result of the Birchwavy Acquisition was also a contributing factor in the decrease in PET's royalty rate.

Operating Costs

Operating costs include all costs associated with the production of oil and natural gas from the wellhead to the point at which the product enters a sales pipeline for transport to market. Field gathering and processing costs are also included in operating costs. Revenue received from the processing of third party production at PET's facilities is netted against operating costs.

Operating costs totaled $102.6 million in 2007 as compared to $84.0 million in 2006. On a unit-of-production basis, operating costs increased by ten percent to $1.65 per Mcfe in 2007 from $1.50 per Mcfe in 2006. Operating costs increased as a result of higher production levels and slightly higher per unit operating costs on the Birchwavy Assets as compared to the Trust's existing properties, as well as higher property tax rates on the Trust's expanding productive acreage base. Much of the total operating costs in northeast Alberta relate to the ongoing operation and maintenance of facilities and other infrastructure and are fixed in nature. As PET continues to expand its facilities in these areas in order to tie in new wells and increase compression the related fixed costs of operations tend to increase.

Transportation Costs

Costs to transport gas from the plant gate to the commercial market sales point are not reflected as an operating cost but rather are recorded as transportation costs for the product. Total transportation costs increased by seven percent to $12.7 million in 2007 from $11.9 million in 2006, in line with the increase in production levels from year to year. On a unit-of-production basis, transportation costs decreased five percent from $0.21 per Mcfe in 2006 to $0.20 per Mcfe in 2007. The 23 percent decrease from 2005 levels is a result of optimization of the Trust's transportation usage as well as the negotiation of natural gas sales contracts directly to end users proximal to the Trust's operations in northeast Alberta, which benefit from reduced gas transportation costs.

Gas over bitumen royalty adjustments

In 2004 and 2005 the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas ("Royalty Regulation"), which 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 certain bitumen conservation decisions. The 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 a 50 percent reduction factor. The components of netbacks for the gas over bitumen shut-in reserves are outlined below:

Gas over bitumen royalty adjustment netback ($ per Mcf)	**2007**	2006	2005
Average deemed volume (MMcf/d)	**19.9**	20.8	22.4
Gas price	**$ 6.21**	$ 6.74	$ 8.30
Royalties	**(1.24)**	(1.35)	(1.66)
Operating costs	**(0.40)**	(0.40)	(0.40)
50% reduction factor	**(2.28)**	(2.49)	(3.12)
Gas over bitumen royalty adjustment netback	**$ 2.29**	$ 2.50	$ 3.12

The Trust's 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. Deemed production decreased by 0.9 MMcf/d from the 20.8 MMcf/d recorded for 2006 as a result of the annual ten percent reduction in deemed production volumes discussed previously partially offset by the acquisition of approximately 2.0 MMcf/d of deemed production in the second quarter of 2007. Current deemed production is approximately 20.0 MMcf/d.

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

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

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.

General and administrative expenses

		2007		2006		2005
	$000's	**$/Mcfe**	$000's	$/Mcfe	$000's	$/Mcfe
Cash general & administrative	**24,670**	**0.40**	16,635	0.30	11,807	0.22
Trust Unit-based compensation (1)	**4,287**	**0.07**	3,337	0.06	1,993	0.04
Total general & administrative	**28,957**	**0.47**	19,972	0.36	13,800	0.26

(1) Non-cash item

General and administrative expenses ("G&A") include costs incurred by PET which are not directly associated with the production of oil and natural gas. The most significant components of G&A expenses are office staff compensation costs and information technology costs. Field employee compensation costs are charged to operating expenses. Overhead recoveries resulting from the allocation of administrative costs to partners are recorded as a reduction of G&A expenses.

G&A expenses, net of overhead recoveries on operated properties, increased to $29.0 million from $20.0 million in 2006 and increased on a unit-of-production basis from $0.36 per Mcfe in 2006 to $0.47 per Mcfe in 2007. The increase in 2007 is largely the result of additional staffing requirements related to the Birchwavy Assets and transition costs on the acquisition. G&A costs have also increased in 2007 due to the move to the Trust's new head office and rent expense on the new space. Trust Unit-based compensation also increased by $1.0 million in 2007 due to a higher number of incentive rights outstanding as compared to the prior year and a charge of $0.5 million relating to a change in PET's unit incentive plan during the year. PET uses a binomial lattice option pricing model to determine compensation expense on unit incentive rights.

Interest expense

Interest and other expense increased to $21.4 million in 2007 from $11.7 million in 2006 as a result of a higher monthly average debt balance following the Birchwavy Acquisition and higher short-term interest rates as compared to 2006. The Trust's average bank debt balance increased to $314 million in 2007 from $225 million in 2006, and average interest rates on bank debt increased from 4.9 percent in 2006 to 5.5 percent in 2007. Interest and other expense also includes a loss on investment of $1.9 million related to the decline in market value of the Trust's investment in Cordero Energy Inc. ("Cordero"), a publicly traded oil and gas exploration company to December 31, 2007. The investment was obtained in the third quarter of 2007 as a result of the acquisition by Cordero of Sebring Energy Ltd., a private oil and gas company in which the Trust had an investment through an exchange of undeveloped lands for shares in 2005. In February 2008 Cordero announced that all of its outstanding shares would be acquired for cash by a government-owned utility. PET expects to realize proceeds of $1.4 million and record a gain of $0.3 million upon closing of the acquisition.

In 2007, $15.6 million of interest on convertible debentures was expensed as compared to $10.4 million in 2006. The increase was due to the issuance of $75 million of 6.5 percent debentures in June 2007 as partial funding for the Birchwavy Acquisition and a full year of interest expense on the 6.25 percent convertible debentures (the "2006 6.25% Debentures") issued in April 2006.

Depletion, depreciation and accretion

PET's 2007 depletion, depreciation and accretion ("DD&A") rate decreased to $3.54 per Mcfe from $3.56 per Mcfe in 2006 primarily due to the cost per Mcfe of proved reserves associated with the Birchwavy Acquisition, offset by higher accretion expense per unit-of-production as compared to the prior year. The Trust calculates its depletion factor using proved reserves for acquired properties, proved developed reserves for other properties and production volumes. Gas over bitumen deemed production is not included in the DD&A calculation. The DD&A rate includes accretion expense on the asset retirement obligation of $10.7 million in 2007 as compared to $7.2 million in 2006. The increase in accretion is a function of the Trust's expanding asset base resulting primarily from the acquisitions completed in 2007. The increase in PET's asset base also contributed to a higher asset retirement obligation which increased from $109.4 million at December 31, 2006 to $194.1 million at December 31, 2007.

Depletion, depreciation and accretion

($ thousands except per Mcfe amounts)	**2007**	2006	2005
Depletion expense	**209,496**	192,052	145,469
Accretion of asset retirement obligation	**10,672**	7,187	3,617
Total	**220,168**	199,239	149,086
Per unit-of-production ($/Mcfe)	**3.54**	3.56	2.80

At year-end 2007, property, plant and equipment costs include $142.9 million (2006 - $80.9 million) currently not subject to depletion and $27.5 million (2006 - $19.5 million) of costs related to shut-in gas over bitumen reserves which are not being depleted due to the non-producing status of the wells in the affected properties.

Income taxes

On June 22, 2007, new legislation was passed (the "Trust Tax Legislation") pursuant to which certain distributions will be subject to a trust-level tax and will be characterized as dividends to the Unitholders, commencing January 1, 2011.

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.

The new trust tax applies to PET effective January 1, 2011 assuming the Trust continues to comply with the "normal growth" provisions as outlined by the federal government. Specifically "normal growth" includes equity growth within certain "safe harbour" limits measured by reference to a Specified Investment Flow Through's ("SIFT") market capitalization as of the end of trading on October 31, 2006. The safe harbour calculation would include only the market value of the SIFT's issued and outstanding publicly-traded trust units and not any convertible debt, options or other interests convertible into or exchangeable for trust units. Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007, and 20 percent each for calendar 2008, 2009 and 2010. These limits are cumulative, so that any unused limit for a period carries over into the subsequent period. Additional details of the guidelines include the following:

(i) new equity for these purposes includes units and debt that is convertible into units, and may include other substitutes for equity;

(ii) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion into trust units of convertible debentures or otherwise, will not be considered growth for these purposes and will therefore not affect the safe harbour; and

(iii) the exchange, for trust units, of exchangeable partnership units or exchangeable shares that were outstanding on October 31, 2006 will not be considered growth for these purposes and will therefore not affect the safe harbour where the issuance of the trust units is made in satisfaction of the exercise of the exchange right by a person other than the SIFT.

The Trust's market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding publicly-traded Trust Units, was approximately $1.4 billion, which means the Trust's "safe harbour" equity growth amount for the period ending December 31, 2007 was approximately $560 million, and for each of calendar 2008, 2009 and 2010 is an additional approximately $280 million, not including equity issued to replace the Trust's debt that was outstanding on October 31, 2006, including convertible debentures. Failure to comply with the "normal growth" provisions as outlined would result in the Trust being subject to the new tax immediately, as opposed to January 1, 2011. Since October 31, 2006 PET has issued approximately $364 million of new Trust Units and convertible debentures through the public offering completed on June 20, 2007, the Trust’s Distribution Reinvestment and Optional Trust Unit Purchase Plan (“DRIP Plan”) and Unit Incentive Plan.

Currently, the Trust Tax Legislation provide 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 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.

PET has not recorded a future income tax liability as a result of the Trust Tax Legislation being enacted. Based on production forecasts included in the independent reserve report for the assets acquired by PET during the period and the independent reserve report on PET’s reserves as at December 31, 2007, the book values of the Trust’s assets are projected to approximate the related tax values by January 1, 2011, the date the direct tax on distributions within the Trust becomes effective. At December 31, 2007, the Trust’s consolidated income tax pools are estimated as follows. Actual tax pool amounts will vary as tax returns are finalized and filed. PET intends to maximize the preservation of tax pools over the transition period in order to minimize the tax consequences faced by the Trust in 2011 and future years.

Tax pool information	**$ millions**
Canadian oil and gas property expense (COGPE)	332.0
Canadian development expense (CDE)	83.2
Canadian exploration expense (CEE)	6.8
Undepreciated capital cost (UCC)	215.9
Trust unit issue costs	23.5
Non-capital losses	71.3
Total	732.7

Net earnings (loss) and funds flow

Funds flow totaled $239.1 million ($2.44 per Trust Unit) for the year ended December 31, 2007 as compared to $236.7 million ($2.82 per Trust Unit) for the year ended December 31, 2006. The increase in funds flow is a result of higher revenues driven by the 11 percent increase in production levels and successful gas price management activities, partially offset by increased operating, general and administrative and interest expenses in 2007 as compared to 2006. Funds flow for 2007 decreased 13 percent on a per Trust Unit basis from 2006, as the financing for the Birchwavy Acquisition led to a 17 percent increase in weighted average Trust Units outstanding for the year.

Funds flow reconciliation	2007 $ millions	2007 ($/Mcfe)	2006 $ millions	2006 ($/Mcfe)
Production volume (Bcfe)	**62.1**		56.0	
Revenue	**462.4**	**7.44**	420.8	7.52
Royalties	**(64.8)**	**(1.04)**	(66.0)	(1.18)
Operating costs	**(102.6)**	**(1.65)**	(84.0)	(1.50)
Transportation costs	**(12.7)**	**(0.20)**	(11.9)	(0.21)
Operating netback from production	**282.3**	**4.55**	258.9	4.63
Gas over bitumen royalty adjustments	**17.3**	**0.28**	18.5	0.33
Lease rentals	**(3.5)**	**(0.06)**	(2.5)	(0.05)
General and administrative [1]	**(24.7)**	**(0.40)**	(16.6)	(0.30)
Interest and other [1]	**(19.5)**	**(0.34)**	(11.7)	(0.21)
Interest on convertible debentures [1]	**(12.8)**	**(0.21)**	(8.6)	(0.15)
Current taxes	**-**	**-**	(1.3)	(0.02)
Funds flow [1] [2]	**239.1**	**3.82**	236.7	4.23

(1) Excludes non-cash items
(2) This is a non-GAAP measure, see "Significant Accounting Policies and Non-GAAP Measures" in this MD&A.

The Trust incurred a net loss of $32.9 million or $0.33 per Trust Unit in 2007 as compared to a net loss of $18.9 million or $0.22 per Trust Unit in 2006, as a result of higher DD&A charges and an unrealized loss on financial instruments of $35.4 million, partially offset by a gain of sale of the Trust's office building of $22.0 million.

Fourth quarter information summary

Fourth quarter information ($ thousands except per Trust Unit, per Mcfe and percent amounts)	**Three months ended December 31** **2007**	2006	% change
Daily production volumes (MMcfe/d)	**190.3**	144.6	32
Oil and natural gas revenues	**109,919**	94,564	16
Realized gains (losses) on financial instruments	**13,828**	9,602	44
Oil and natural gas revenues, after financial hedging	**123,747**	104,166	19
Natural gas price, before financial hedging and physical forward sales ($/Mcfe)	**$ 6.19**	$ 6.59	(6)
Realized natural gas price ($/Mcfe)	**$ 7.07**	$ 7.83	(10)
Royalties	**15,202**	13,164	15
Royalties as a percentage of revenues (%)	**12.3**	12.6	(2)
Operating expenses	**29,221**	21,942	33
Per Mcfe	**$ 1.67**	$ 1.65	1
General and administrative ("G&A") expenses	**7,733**	6,769	14
Per Mcfe	**$ 0.44**	$ 0.51	(14)
Funds flow	**59,622**	58,166	3
Per Trust Unit	**$ 0.55**	$ 0.69	(20)
Cash flow provided by operating activities	**38,224**	56,693	(33)
Per Trust Unit	**0.35**	0.67	(48)
Net earnings (loss)	**(4,970)**	(68,254)	(93)
Per Trust Unit	**$ (0.05)**	$ (0.80)	(94)
Capital expenditures – exploration and development	**20,270**	24,104	(16)

In comparing the fourth quarter of 2007 with the same period in 2006:

- Production increased 32 percent to 190.3 MMcfe/d, primarily due to the Birchwavy Acquisition completed in June 2007.
- Realized natural gas prices were ten percent lower in the fourth quarter of 2007 as a result of lower AECO daily spot and monthly index prices compared to the three months ended December 31, 2006.
- The Trust's royalty rate of 12.3 percent of revenues was consistent with 2006 and lower than the Trust's historical royalty rates as realized natural gas prices were well above the Alberta Gas Reference Price in both quarters.
- General and administrative expenses increased $0.9 million from the fourth quarter of 2006, as a result of higher staffing levels related to the Birchwavy Assets.
- Operating costs increased $7.3 million due to higher production volumes. On a unit-of-production basis operating costs were consistent from quarter to quarter.
- Funds flow increased $1.4 million to $59.6 million for the fourth quarter of 2007 as higher oil and natural gas revenues were partially offset by higher operating and interest costs.
- A net loss of $5.0 million was recorded for the three months ended December 31, 2007, as a result of an unrealized loss on financial instruments of $17.4 million and higher DD&A charges as compared to prior quarters, partially offset by a gain on sale of the Trust's office building of $22.0 million. The $68.3 million loss in the fourth quarter of 2006 relates primarily to $58.7 million in natural gas asset write-downs recorded in the quarter.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Capitalization and financial resources	Year ended December 31	
($ thousands except per Trust Unit and percent amounts)	**2007**	2006
Bank debt	**342,190**	222,923
Convertible debentures, measured at principal amount	**236,109**	161,134
Working capital deficiency (surplus) [2]	**(6,519)**	22,561
Net debt	**571,780**	406,618
Trust Units outstanding at end of period (thousands)	**109,557**	85,186
Market price at end of period	**6.30**	12.40
Market value of Trust Units	**690,209**	1,056,306
Total capitalization [1]	**1,261,909**	1,462,924
Net debt as a percentage of total capitalization (%)	**45.3**	27.8
Annualized fourth quarter funds flow [1]	**238,488**	232,664
Net debt to funds flow ratio (times) [1]	**2.4**	1.7

(1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in this MD&A.
(2) Working capital deficiency (surplus) excludes short-term financial instrument assets and liabilities related to the Trust's hedging activities.

PET has a demand credit facility with a syndicate of Canadian chartered banks. The revolving feature of the facility expires on May 26, 2008 if not extended. Upon expiry of the revolving feature of the facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity of one additional year. The borrowing base on the facility is currently $400 million, comprised of a $390 million production component and a $10 million working capital component. Collateral for the credit facility is provided by a floating-charge debenture covering all existing and acquired property of the Trust as well as unconditional full liability guarantees from all subsidiaries in respect of amounts borrowed under the facility. Bank debt increased to $342.2 million at December 31, 2007, as compared to $222.9 million at December 31, 2006 as a result of property acquisitions during the year and expenditures related to the Trust's capital programs, offset somewhat by proceeds received through the Trust's DRIP program and funds flows in excess of distributions during the year. PET also sold its office building during the year for net proceeds of $35 million after realtor fees, which were used to eliminate the building mortgage and reduce outstanding indebtedness. In addition to amounts outstanding under the credit facility PET has outstanding letters of credit in the amount of $4.38 million.

Net debt as a percentage of total capitalization increased to 45.3 percent at year-end 2007 as compared to 27.8 percent in the prior year, as a result of higher debt levels and a decline in the market price of the Trust's units during the year. Net debt to annualized fourth quarter funds flow rose to 2.4 times for the three months ended December 31, 2007 from 1.7 times for the three months ended December 31, 2006. A reconciliation of the change in net debt from December 31, 2006 to December 31, 2007 is as follows.

Reconciliation of net debt ($ millions)	
Net debt, December 31, 2006	406.6
Capital expenditures (exploration & development and other)	119.3
Acquisitions, net of dispositions	404.2
Issuance of Trust Units, net of issue costs	(236.5)
Issue costs for 6.5% convertible debentures	3.0
Funds flow	(239.1)
Distributions	145.8
Proceeds from DRIP plan	(32.9)
Reclassification of long-term investment to marketable securities	(1.1)
Proceeds on exercise of Incentive Rights	(0.1)
Expenditures on asset retirement obligations	2.6
Net debt, December 31, 2007	**571.8**

The Trust expects that its distributions and capital expenditure program for 2008 will be funded by funds flow and proceeds from PET's DRIP plan will be used to fund longer term, exploratory components of PET's capital program such as undeveloped land acquisitions and seismic expenditures. However, changes in natural gas prices, cash netbacks and production levels can affect future capital spending plans and distributions.

PET's future contractual obligations are summarized in the following table:

		Payments due by period			
Contractual obligations ($millions)	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
Bank and other debt [1]	342.2	-	342.2	-	-
Convertible debentures	236.1	-	61.1	175.0	-
Pipeline commitments [2]	23.0	9.3	8.9	3.9	0.9
Total contractual obligations	601.3	9.3	412.2	178.9	0.9

(1) The revolving feature of the credit facility expires on May 26, 2008 if not extended. Upon expiry of the revolving feature of the facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity date of one additional year.

(2) The Trust has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada.

Convertible debentures

As at December 31, 2007, the Trust had 6.5 percent convertible debentures issued in June 2007 (6.5% Debentures), 6.25 percent convertible debentures issued in April 2006 (2006 6.25% Debentures), 6.25 percent convertible debentures issued in April 2005 (2005 6.25% Debentures) and 8 percent convertible debentures issued in July 2004 (8% Debentures) outstanding as follows:

Convertible debentures series	6.50%	2006 – 6.25%	2005 – 6.25%	8%
Principal issued ($millions)	75.0	100.0	100.0	48.0
Principal outstanding ($millions)	75.0	100.0	55.3	5.9
Maturity date	June 30, 2012	April 30, 2011	June 30, 2010	September 30, 2009
Conversion price ($ per Trust Unit)	14.20	23.80	19.35	14.20
Fair market value ($millions)	64.4	83.0	47.3	5.8

All series of debentures are redeemable by the Trust at a premium to face value, pay interest semi-annually and are subordinated to substantially all other liabilities of PET including the credit facility. Fair values of debentures are calculated by multiplying the number of debentures outstanding at December 31, 2007 by the quoted market price per debenture at that date. The value of conversions of debentures into Trust Units during 2007 was less than $0.1 million.

Unitholders' equity

PET's total capitalization was $1.3 billion at December 31, 2007 with the market value of the Trust Units representing 54.6 percent of total capitalization. During 2007, the market price of the Trust Units ranged from $5.70 to $13.18 with an average daily trading volume of 412,000 Trust Units.

PET has a distribution reinvestment and optional Unit purchase plan ("DRIP plan") which provides Unitholders with 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 price of the Trust Units for the 10 trading days immediately proceeding a distribution payment date ("Treasury Purchase Price"). As well, subject to thresholds and restrictions described in the DRIP plan, it contains a provision for the purchase by Canadian unitholders of additional Trust Units with optional cash payments of up to $100,000 per participant per fiscal year of PET at the same six percent discount to the Treasury Purchase Price. No additional commissions, service or brokerage fees are charged to the Unitholder for these transactions. In 2007 the DRIP plan resulted in an additional 3,675,000 Trust Units (2006 – 2,139,000 Trust Units) being issued at an average price of $8.95 (2006 - $16.96) raising a total of $32.9 million (2006 - $36.3 million).

Weighted average Trust Units outstanding for 2007 totaled 98.1 million (2006 – 83.9 million). On December 31, 2007 there were 109.6 million Trust Units outstanding. In addition to issuances under the DRIP plan, 245,000 Trust Units were issued during 2007 by way of exercised Incentive Rights and Bonus Rights for net proceeds of $0.1 million.

CASH DISTRIBUTIONS

Distributions are determined monthly by the Board of Directors of the Trust's administrator taking into account PET's forecasted production, capital spending and cash flow, forward natural gas price curves, the Trust's current hedging position, targeted debt levels and debt repayment obligations. The following items are considered in arriving at cash distributions to Unitholders:

- Base production forecasts;
- Current financial and physical forward natural gas sales contracts ;
- Forward market for natural gas prices;
- Exploration and development expenditures;
- Projected production additions;
- Debt repayments to the extent required or deemed appropriate by management to preserve balance sheet strength for future opportunities;
- Working capital requirements; and
- Site reclamation and abandonment expenditures.

PET declared cash distributions of $145.8 million ($1.50 per Unit) in 2007 representing 61.0 percent of annual funds flow, bringing total cumulative distributions since inception to year-end 2007 to $817.2 million ($11.924 per Trust Unit). In 2006, declared cash distributions were $221.8 million ($2.64 per Trust Unit), representing 93.7 percent of funds flow. PET's business strategy targets sustainability with a capital program sufficient to maintain production levels and with the remaining cash flow available for distribution to Unitholders. The Trust's distribution levels and payout ratio were adjusted in 2007 to preserve sustainability and strengthen its balance sheet in light of weaker natural gas prices. The payout ratio in future periods will largely be determined by the Trust's capital spending plans and resulting production levels, royalty rates, operating costs and natural gas prices, which have experienced significant volatility in 2007.

PET anticipates that distributions and development capital expenditures for 2008 will be funded by funds flow and proceeds from the DRIP plan be used to fund longer term, exploratory components of PET's capital program such as undeveloped land acquisitions and seismic expenditures; however, changes in natural gas prices, cash netbacks and production levels can affect future capital spending plans and distributions. Acquisitions will continue to be funded through a combination of internally generated funds, equity offerings and debt financing.

	Year ended December 31	
Distributions ($thousands)	**2007**	2006
Cash flows provided by operating activities	**222,937**	228,581
Net earnings (loss)	**(32,859)**	(18,850)
Distributions	**145,829**	221,789
Excess of cash flows provided by operating activities over distributions	**77,108**	6,792
Shortfall of net earnings (loss) over distributions	**(178,688)**	(240,639)

The Trust targets long-term sustainability of both its production base and distributions to Unitholders. As such, PET's distribution rates are designed to result in an excess of cash flows provided by operating activities over distributions which will provide the majority of the funding for PET's exploration and development expenditures for the respective periods. The excess of $77.1 million compares to exploration and development expenditures (before exploration costs and undeveloped land purchases) of $98.9 million for the year ended December 31, 2007. The excess of cash flows provided by operating activities over distributions increased significantly in 2007 as compared to 2006 as the Trust adjusted its distribution rate in order to preserve sustainability. In periods where the excess of cash flows provided by operating activities over distributions is less than exploration and development expenditures, the shortfall is funded by proceeds from the Trust's DRIP program, additional bank borrowings and external financing activities as appropriate.

The Trust has an excess of distributions over net earnings in 2007 and 2006, and distributions are likely to continue to exceed net earnings in future periods. PET does not typically compare distributions to earnings due to the significant impact of non-cash items on earnings such as unrealized gains and losses on financial instruments, asset impairment charges and DD&A, which have no impact on the Trust's ability to pay distributions. Where distributions exceed net earnings, a portion of the cash distributions declared may represent an economic return of capital to the Trust's Unitholders.

Taxation of 2007 cash distributions

Cash distributions are comprised of a return of capital portion (tax deferred) and a return on capital portion (taxable). In order to preserve tax pools to shield the Trust from SIFT income taxes in 2011 and beyond, PET has elected to minimize its tax pool claims in 2007. As such, cash distributions received or receivable by a Canadian resident, outside of a registered pension or retirement plan in the 2007 taxation year, are 100 percent taxable. Consistent with the Trust's strategy of conserving tax pools, distributions are expected to be 100 percent taxable for the foreseeable future.

2007 Distributions by month ($ per Trust Unit) **Payment Date**	**Canadian Taxable Amount**	**Canadian Tax Deferred Amount (Return of capital)**	**Total Distribution**
February 15, 2007	0.20	0.00	0.20
March 15, 2007	0.14	0.00	0.14
April 16, 2007	0.14	0.00	0.14
May 15, 2007	0.14	0.00	0.14
June 15, 2007	0.14	0.00	0.14
July 16, 2007	0.14	0.00	0.14
August 15, 2007	0.10	0.00	0.10
September 17, 2007	0.10	0.00	0.10
October 15, 2007	0.10	0.00	0.10
November 15, 2007	0.10	0.00	0.10
December 17, 2007	0.10	0.00	0.10
January 15, 2008	0.10	0.00	0.10
Total (1)	**$ 1.50**	**$ 0.00**	**$ 1.50**
Percent	**100**	**0**	**100**

(1) Total is based upon cash distributions declared during 2007.

SUMMARY OF QUARTERLY RESULTS

($ thousands except where noted)	**Dec 31, 2007**	Sep 30, 2007	Jun 30, 2007 (restated) (3)	Mar 31, 2007
				Three months ended
Oil and natural gas revenues before royalties (1)	**109,919**	98,508	104,451	99,693
Natural gas production (MMcfe/d)	**190.3**	193.1	155.0	141.7
Funds flow (2)	**59,622**	41,212	72,669	65,597
Per Trust Unit - basic	**0.55**	0.38	0.81	0.76
Net earnings (loss)	**(4,970)**	5,246	9,218	(39,261)
Per Trust Unit - basic	**(0.05)**	0.05	0.10	(0.46)
- diluted	**(0.05)**	0.05	0.10	(0.46)
Realized natural gas price ($/Mcfe)	**7.07**	5.66	8.80	8.94
Average AECO Daily Index price ($/GJ)	**6.01**	5.14	7.07	7.40

($ thousands except where noted)	Three months ended Dec 31, 2006	Sept 30, 2006	June 30, 2006	Mar 31, 2006
Oil and natural gas revenues before royalties [1]	94,564	96,576	97,856	112,639
Natural gas production (MMcfe/d)	144.6	154.6	162.9	151.5
Funds flow [2]	58,166	60,770	56,605	61,112
Per Trust Unit - basic	0.69	0.72	0.68	0.74
Net earnings (loss)	(68,254)	19,619	21,816	7,969
Per Trust Unit - basic	(0.80)	0.23	0.26	0.10
- diluted	(0.80)	0.23	0.26	0.10
Realized natural gas price ($/Mcfe)	7.83	7.36	6.85	8.09
Average AECO Daily Index price ($/GJ)	6.54	5.36	5.71	7.13

(1) Excludes realized and unrealized gains (losses) on financial instruments.

(2) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in this MD&A.

(3) The Trust's net earnings for the three and six months ended June 30, 2007 have been restated to reflect the correction of an error with respect to the vesting period over which certain unit-based compensation liabilities were expensed. The correction results in an increase to net earnings for the three and six months ended June 30, 2007 of $3.1 million.

Despite wide fluctuations in AECO gas prices over the last eight quarters, natural gas revenues have been reasonably consistent from quarter to quarter as the impact of increased production volumes in the past two quarters has been offset by lower AECO natural gas prices. AECO price fluctuations have been partially mitigated by fixed-price physical delivery natural gas contracts entered into by the Trust over these periods, which have also been a contributing factor to the consistency in revenues from quarter to quarter. Funds flows are impacted primarily by PET's realized gas price and changes in production levels; funds flows are highest in the first two quarters of 2007 and lowest in the third quarter of 2007 when the realized gas price was $5.66/Mcfe.

Net earnings were highest in the second and third quarters of 2006 as a result of gas over bitumen revenues of $13.7 million related to the sale of certain shut-in natural gas properties and unrealized gains on financial instruments of $14.0 million, respectively. The net loss in the fourth quarter of 2006 was a result of impairment charges at east central Alberta and Saskatchewan, higher DD&A expenses and higher operating costs as compared to previous quarters. The net loss in the first quarter of 2007 is due to a $48.5 million unrealized loss on the change in mark-to-market value of PET's financial instruments during the period.

2008 OUTLOOK AND SENSITIVITIES

The following table shows PET's estimate of key measures for 2008 based on PET's hedging portfolio, production levels and the Trust's estimated exploration and development capital expenditures and targeted results for the year under several different AECO gas price assumptions.

	Average AECO monthly index gas price ($/GJ) [3]			
Cash flow outlook	$6.00	$7.00	$8.00	$9.00
Realized gas price ($/Mcfe)	7.15	7.66	8.20	8.69
Cash flow [1] ($million)	226	251	278	302
Per Trust Unit [1] ($/Unit/month)	0.17	0.19	0.21	0.23
Payout ratio [1] [4] (%)	59	53	48	44
Ending net debt to cash flow ratio [2] (times)	2.4	2.1	1.8	1.6

(1) These are non-GAAP terms; please refer to "Significant accounting policies and non-GAAP measures" in this MD&A.

(2) Calculated as ending net debt (including convertible debentures) divided by annualized funds flow.

(3) Average forward AECO price for March-December 2008 as at March 7, 2008 was $8.47/GJ.

(4) Estimated payout ratio assumes a distribution rate of $0.10 per month per Trust Unit for 2008.

Below is a table that shows sensitivities of PET's 2008 estimated funds flow to operational changes and changes in the business environment:

Funds flow sensitivity analysis ($ per Trust Unit)	Change	Impact on funds flow per Trust Unit Annual	Monthly
Business Environment			
Price per Mcfe	$ 0.25	0.06	0.005
Interest rate on debt	1%	0.03	0.002
Operational			
Production volume	5 MMcfe/d	0.11	0.009
Operating costs	$ 0.10/Mcfe	0.06	0.005
Cash general and administrative expenses	$ 0.10/Mcfe	0.06	0.005

The Trust's outlook and sensitivities assume operating costs of $1.70 per Mcfe, cash general and administrative expenses of $0.36 per Mcfe, an interest rate on bank debt of 5.75 percent and incorporate the Trust's hedging portfolio at March 7, 2008. Cash general and administrative expenses are equal to general and administrative expenses before Trust Unit-based compensation.

OTHER SIGNIFICANT ACCOUNTING POLICIES AND NON-GAAP MEASURES

Payout ratio

Payout ratio refers to distributions on Trust Units measured as a percentage of funds flow for the period and is used by management to analyze funds flow available for development and acquisition opportunities as well as overall sustainability of distributions. Funds flow does not have any standardized meaning prescribed by GAAP and therefore payout ratio may not be comparable to the calculation of similar measures for other entities.

Operating and funds flow netbacks

Operating and funds flow netbacks are used by management to analyze margin and funds flow on each Mcf of natural gas production. Operating and funds flow netbacks do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to the calculation of similar measures for other entities. Operating and funds flow netbacks should not be viewed as an alternative to cash from operating activities, net earnings per Trust Unit or other measures of financial performance calculated in accordance with GAAP.

Revenue, including realized gains (losses) on financial instruments

Revenue, including realized gains (losses) on financial instruments is used by management to calculate the Trust's net realized natural gas price taking into account monthly settlements on financial forward natural gas sales and foreign exchange contracts. These contracts are put in place to protect PET's funds flows from potential volatility in natural gas prices, and as such any related realized gains or losses are considered part of the Trust's natural gas price. Revenue, including realized gains (losses) on financial instruments does not have any standardized meaning as prescribed by GAAP and should not be reviewed as an alternative to Revenue or other measures calculated in accordance with GAAP.

Total capitalization

Total capitalization is equal to net debt including convertible debentures plus market value of issued equity and is used by management to analyze leverage. Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

CRITICAL ACCOUNTING ESTIMATES

The MD&A is based on the Trust's consolidated financial statements which have been prepared in Canadian dollars in accordance with GAAP. The application of GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. PET bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

Following is a discussion of the critical accounting estimates that are inherent in the preparation of the Trust's consolidated financial statements and notes thereto.

Accounting for petroleum and natural gas operations

Under the successful efforts method of accounting, the Trust capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Exploration expenditures including geological and geophysical costs, lease rentals and exploratory dry holes are charged to earnings in the period incurred. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze and the determination that proved reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of land in a given area.

Reserve estimates

Estimates of the Trust's reserves included in its consolidated financial statements are prepared in accordance with guidelines established by the Canadian Securities Administrators. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

PET's reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate. The present value of future net revenues should not be assumed to be the current market value of the Trust's estimated reserves. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations. The estimates of reserves impact depletion, dry hole expenses and asset retirement obligations. If reserve estimates decline, the rate at which the Trust records depletion increases thereby reducing net earnings. In addition, changes in reserve estimates may impact the outcome of PET's assessment of its petroleum and natural gas properties for impairment.

Purchase price allocation

Corporate acquisitions are accounted for by the purchase method of accounting whereby the purchase price is allocated to the assets and liabilities acquired based on their fair values as estimated by management at the time of acquisition. The excess of the purchase price over the fair values represents goodwill. In order to estimate fair values, management has to make various assumptions including commodity prices, reserves acquired and discount rates. Differences from these estimates may impact the future financial statements of the Trust.

Impairment of petroleum and natural gas properties

The Trust reviews its proved properties for impairment on an operational field basis. For each property, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of that property may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the future net revenues from the property as estimated by the Trust on the balance sheet date. Reserve estimates and estimates for natural gas prices and production costs may change and there can be no assurance that impairment provisions will not be required in the future.

Management's assessment of, among other things, the results of exploration activities, commodity price outlooks and planned future development and sales impacts the amount and timing of impairment provisions.

Asset retirement obligations

The asset retirement obligations recorded in the consolidated financial statements are based on an estimate of the fair value of the total costs for future site restoration and abandonment of the Trust's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, the timing of asset retirement expenditures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors including changing technology and political and regulatory environments. PET engages an independent environmental consulting firm to analyze and prepare an annual estimate of the Trust's asset retirement obligations in accordance with National Instrument 51-101. The asset retirement obligation does not include any adjustment for the net salvage value of tangible equipment and facilities.

CHANGE IN ACCOUNTING POLICY

In 2005 the Canadian Institute of Chartered Accountants ("CICA") issued new standards for the recognition, measurement and disclosure of financial instruments. Under the new standards which were effective January 1, 2007, PET's portfolio of forward fixed-price natural gas sales contracts and AECO/NYMEX fixed-basis contracts (collectively "physical hedging contracts") are considered non-financial derivatives and are accounted for as financial instruments. Accordingly, the fair values of the Trust's physical hedging contracts as at January 1, 2007 were recorded as an asset of $30.6 million on the Trust's balance sheet with an offsetting credit to retained earnings. The fair values of the physical hedging contracts were calculated by PET based on an independently obtained forward natural gas price curve as at January 1, 2007.

Changes in fair value of these contracts during 2007 as well as fair values of other physical and financial natural gas hedging contracts entered into during year measured as at December 31, 2007 were included in net earnings for the period. The decrease in fair value during the period was $35.4 million, which has been included in "unrealized loss on financial instruments" on PET's statement of earnings (loss) for the year ended December 31, 2007.

As the change in accounting policy was applied prospectively there is no related impact on earnings for previous periods.

NEW ACCOUNTING PRONOUNCEMENTS

On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, Capital Disclosures, Section 3862, Financial Instruments – Disclosures, and Section 3863, Financial Instruments – Presentation. These new standards will be effective on January 1, 2008.

Section 1535 involves new disclosures regarding an entity's objectives, policies and processes for managing capital, including discussions on an entity's compliance with any potential capital requirements.

Sections 3862 and 3863 specify standards of presentation and enhanced disclosure on financial instruments. Increased disclosure will be required on the risks arising from financial instruments and how the entity manages those risks.

The Trust is currently evaluating the potential impact of these new sections on its financial statements.

RISK FACTORS

PET's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting others in both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Trust's financial position, results of operations, and cash available for distribution to Unitholders are directly impacted by these factors.

Income Taxes

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 market 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.

Gas over bitumen issue

Recent decisions by the Alberta Energy and Utilities Board ("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 in previous years.

On July 24, 2007 the AEUB released Decision 2007-056 related to the application for shut-in of certain natural gas production in the Cold Lake area in northeast Alberta. Although PET does not produce natural gas from the formations of concern in the area identified in Decision 2007-056, the AEUB did note in its conclusions that a broad bitumen conservation strategy may be required for all areas where natural gas production may interfere with eventual bitumen recovery. In 2007 the AEUB was reorganized and responsibility for oil and natural gas industry regulation was transferred to the newly created Energy Resources Conservation Board ("ERCB"). 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.

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.

Depletion of reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions, 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 and natural gas reserves. PET will not be reinvesting cash flow in the same manner as other industry participants as one of the main objectives of the Trust is to maximize long-term distributions. Accordingly, absent capital injections, PET's initial production levels and reserves will decline.

PET's future oil and natural gas reserves and production, and therefore its funds flows, will be highly dependent on PET's success in exploiting its reserve base and acquiring additional reserves. Without reserves additions through acquisition or development activities, the Trust's reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital including the issuance of additional Trust Units become limited or unavailable PET's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that PET is required to use funds flow to finance capital expenditures or property acquisitions, the level of distributions will be reduced.

PET reinvests capital to minimize the effects of natural production decline on its asset base. The Trust currently estimates that capital expenditures of $100 million to $130 million annually are required to maintain production at current levels. There can be no assurance that PET will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Reserve estimates

Estimates of PET's 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.

Cyclical and seasonal impact on industry

The Trust's 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 the Trust's financial condition.

Operational matters

The Trust's operations may be delayed or unsuccessful for many reasons including cost overruns, lower natural gas prices, equipment shortages, mechanical and technical difficulties and labour problems. The Trust's 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. PET 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.

Continuing production from a property, and to some extent marketing of production there from, are largely dependent upon economic variables and the ability of the operator of the property. Operating costs on most properties have increased significantly over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Trust to certain properties. A reduction in distributions on Trust Units could result in such circumstances.

Expansion of operations

The operations and expertise of management of the Trust are currently focused on natural gas production and development in the Western Canadian Sedimentary Basin. In the future, the Trust may acquire oil and 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.

Acquisitions

The price paid for asset acquisitions is based on the Trust's internal assessment of the reserves and future production potential adjusted for risk. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas, and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the working interests, management and the Trust. In particular, changes in prices of and markets for petroleum and natural gas from those anticipated at the time of making such assessments will affect the amount of future distributions and as such the value of the Trust Units. In addition, all such estimates involve a measure of geological and engineering uncertainty which could result in lower production and reserves than attributed to the working interests. Actual reserves could vary materially from these estimates. Consequently, the reserves acquired may be less than expected, which could adversely impact funds flows and distributions to Unitholders.

Debt service

Amounts paid in respect of interest and principal on debt will reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of distributions. Certain covenants of the agreements with PET's lenders may also limit distributions. Although PET believes the credit facilities will be sufficient for the Trust's immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of the Trust or that additional funds will be able to be obtained.

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

Net asset value

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

Insurance risk

Exploration for natural gas and the production of natural gas are hazardous undertakings. 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 the Trust's revenues or increase costs and have a material adverse effect on the Trust's operations or financial condition.

PET 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 PET's financial position and reduce or eliminate distributions to Unitholders.

Additional financing

PET's primary source of bank financing is a demand credit facility with a syndicate of Canadian chartered banks in the amount of $400 million. The revolving nature of the credit facility is presently due to expire on May 26, 2008. PET expects that the facility will be extended at that date. If the facility is not extended it will be subject to a one year term-out provision and the Trust 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, PET may be unable to effectively operate its business or pay distributions to Unitholders.

In the normal course of making capital investments to maintain and expand the oil and natural gas reserves of the Trust, additional Trust Units are issued from treasury which may result in a decline in production per Trust Unit and reserves per Trust Unit. Additionally, from time to time the Trust issues 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, the Trust's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that PET is required to use funds flow to finance capital expenditures or property acquisitions, to pay debt services charges or to reduce debt, distributions will be reduced.

Hedging

The nature of PET's operations results in exposure to fluctuations in commodity prices. The Trust will monitor and, when appropriate, utilize derivative financial instruments and physical delivery contracts to mitigate its exposure to these risks. PET may be exposed to credit-related losses in the event of non-performance by counter-parties to the financial instruments. From time to time the Trust may enter into risk management 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 the Trust will receive a minimum price for natural gas production;
- buying a collar under which the Trust will receive a price within a specified price range for natural gas production;
- entering into fixed price contract for natural gas production; and
- entering into contracts to fix the basis differential between natural gas markets.

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

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

- PET is unable to produce sufficient quantities of natural gas to fulfill its obligations;
- PET is required to pay a margin call on a financial hedge contract; or
- PET is required to pay royalties based on a market or reference price that is higher than its hedged fixed or ceiling price.

Non-resident ownership of Trust Units

In order for the Trust to maintain its status as a mutual fund trust under the Income Tax Act, the Trust intends to comply with the requirements of the Income Tax Act for "mutual fund trusts" at all relevant times. In this regard, the Trust shall among other things, monitor the ownership of the Trust Units to carry out such intentions. The Trust Indenture provides that if at any time the Trust becomes aware that the beneficial owners of 48 percent or more of the Trust Units then outstanding may be non-residents or that such a situation is imminent, the Trust shall take such actions as may be necessary to carry out the foregoing intention.

Accounting write-downs as a result of GAAP

GAAP requires that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in the consolidated financial statements of the Trust. 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 unfavorably 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.

Renegotiation or termination of contracts

As at the date hereof, the Trust does not anticipate that any aspect of its business will be materially affected in the current fiscal year by the renegotiation or termination of contracts or subcontracts.

Competitive conditions

The Trust is a member of the petroleum industry which is highly competitive at all levels. The Trust competes with other companies and other energy trusts for all of its business inputs including exploitation and development prospects, access to commodity markets, property and corporate acquisitions, and available capital. The Trust endeavours to be competitive by maintaining a strong financial condition through attracting and retaining technically competent and accountable staff, by refining and enhancing business processes on an ongoing basis and by utilizing current technologies to enhance exploitation, development and operational activities.

Environmental considerations

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

PET is 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 the Trust's licenses. As a result, anyone who suffers losses or damages as a result of pollution caused by PET's operations can claim compensation without needing to demonstrate that the damage is due to any fault on the Trust's part.

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

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

For example, the Canadian government has adopted the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change. As a result, new requirements and regulations may be implemented which would require PET 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 the Trust's operations or financial condition. Any abandonment costs PET incurs will reduce distributions to Unitholders.

The Trust is proactive in its approach to environmental concerns. Procedures are in place to ensure that due care is taken in the day-to-day management of its properties. All government regulations and procedures are followed in adherence to the law. The Trust believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to the Trust.

Government regulation risk

PET operates in a highly regulated industry and it is possible any changes in such regulation or adverse regulatory decisions could affect our production which could reduce distributions to Unitholders. Additional details with respect to the gas over bitumen regulatory issue are described elsewhere in this MD&A.

Commodity price, foreign exchange and interest rate risk

The two most important factors affecting the level of cash distributions available to Unitholders are the level of production achieved by PET, and the price received for its production. These prices are influenced in varying degrees by factors outside the Trust's control. Some of these factors include:

- economic conditions which influence the demand for natural gas and the level of interest rates set by the governments of Canada and the U.S.;
- weather conditions that influence the demand for natural gas;
- transportation availability and costs; and
- price differentials among markets based on transportation costs to major markets.

To mitigate these risks, PET has an active hedging program in place based on an established set of criteria that has been approved by the Board of Directors of the Administrator. The results of the hedging program are reviewed against these criteria and the results actively monitored by the Board.

Beyond our hedging strategy, PET also mitigates risk by having a diversified gas marketing portfolio and by transacting with a number of counter-parties and limiting exposure to each counter-party.

The contracts that PET has with aggregators vary in length. They represent a blend of domestic markets with fixed and floating prices designed to provide price diversification to our revenue stream.

Nature of Trust Units

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation. The Trust's sole assets will be the royalty interests in the properties. The price per Trust Unit is a function of anticipated distributable income, the properties acquired by PET and PET's ability to effect long-term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire stable oil and natural gas properties. Changes in market conditions may adversely affect the trading prices of the Trust Units.

FORWARD-LOOKING INFORMATION

This MD&A contains forward-looking information with respect to PET.

The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements. We believe the expectations reflected in these forward-looking statements are reasonable. However, we cannot assure the reader that these expectations will prove to be correct. The reader should not unduly rely on forward-looking statements included in this report. These statements speak only as of the date of the MD&A.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- the quantity and recoverability of PET's reserves;
- the timing and amount of future production;
- prices for natural gas produced;
- operating and other costs;
- business strategies and plans of management;
- supply and demand for natural gas;
- expectations regarding PET's access to capital to fund its acquisition exploration and development activities;
- the disposition swap, farm in, farm out or investment in certain exploration properties using third party resources;
- the use of exploration and development activity and acquisitions to replace and add to reserves;
- the impact of changes in natural gas prices on funds flow after hedging;
- drilling, completion, facilities and construction plans;
- the existence, operations and strategy of the commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed;
- the Trust's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived there from;
- the impact of Canadian federal and provincial governmental regulation on the Trust relative to other issuers;
- PET's treatment under governmental regulatory regimes;
- the goal to sustain or grow production and reserves through prudent asset management and acquisitions;
- the emergence of accretive growth opportunities; and
- PET's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets.

PET's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A which include but are not limited to:

- volatility in market prices for natural gas;
- risks inherent in PET's operations;
- uncertainties associated with estimating reserves;
- competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and process problems;
- general economic conditions in Canada, the United States and globally;
- industry conditions including fluctuations in the price of natural gas;
- royalties payable in respect of PET's production;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- unanticipated operating events that can reduce production or cause production to be shut-in or delayed;
- stock market volatility and market valuations; and
- the need to obtain required approvals from regulatory authorities.

The above list of risk factors should not be construed as exhaustive.

Additional information on PET, including the most recent filed Annual Report and Annual Information Form, can be accessed at www.sedar.com or from the Trust's website at www.paramountenergy.com.