PARAMOUNT ENERGY TRUST

2009

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**		
	2009	2008	% change	**2009**	2008	% change
FINANCIAL						
Revenue (1) (2)	**78,852**	121,163	(35)	**418,323**	545,701	(23)
Funds flow (2)	**39,409**	61,513	(36)	**231,347**	275,434	(16)
Per Trust Unit (2) (3)	**0.32**	0.55	(42)	**1.96**	2.47	(21)
Cash flow provided by operating activities	**36,446**	69,179	(47)	**228,352**	259,764	(12)
Per Trust Unit (3)	**0.29**	0.61	(52)	**1.93**	2.33	(17)
Net earnings (loss)	**(11,287)**	(8,986)	26	**14,393**	30,785	(53)
Per Trust Unit (3)	**(0.09)**	(0.08)	13	**0.12**	0.28	(57)
Cash distributions	**18,810**	33,885	(44)	**75,838**	133,921	(43)
Per Trust Unit (4)	**0.15**	0.30	(50)	**0.64**	1.20	(47)
Payout ratio (%) (2)	**47.7**	55.1	(13)	**32.8**	48.6	(33)
Total assets	**1,065,305**	1,105,689	(4)	**1,065,305**	1,105,689	(4)
Net bank and other debt outstanding (2) (5)	**270,843**	284,835	(5)	**270,843**	284,835	(5)
Convertible debentures, measured at principal amount	**230,168**	236,034	(2)	**230,168**	236,034	(2)
Total net debt (2) (5)	**501,011**	520,869	(4)	**501,011**	520,869	(4)
Unitholders' equity	**253,879**	257,426	(1)	**253,879**	257,426	(1)
Capital expenditures						
Exploration and development	**10,107**	28,329	(64)	**68,171**	126,091	(46)
Acquisitions, net of dispositions	**(10,016)**	(2,143)	367	**103,885**	(18,514)	661
Other	**377**	927	(59)	**649**	1,588	(59)
Net capital expenditures	**468**	27,113	(98)	**172,705**	109,165	58
TRUST UNITS OUTSTANDING (thousands)						
End of period	**126,224**	112,968	12	**126,224**	112,968	12
Weighted average	**125,064**	112,865	11	**118,181**	111,473	6
Diluted	**126,149**	112,865	12	**119,266**	112,823	6
March 1, 2010	**127,773**			**127,773**		

FINANCIAL AND OPERATING HIGHLIGHTS CONTINUED	Three Months Ended December 31			Year Ended December 31		
	2009	2008	% change	**2009**	2008	% change
OPERATING						
Production						
Total (Bcfe) (6)	**13.4**	15.9	(16)	**57.5**	66.7	(14)
Average daily (MMcfe/d) (6)	**145.9**	173.1	(16)	**157.7**	182.2	(13)
Per Trust Unit (cubic feet equivalent/d/Unit) (3)	**1.17**	1.53	(24)	**1.33**	1.63	(18)
Gas over bitumen deemed production (MMcf/d) (7)	**24.6**	18.1	36	**19.9**	19.2	4
Average daily (actual and deemed – MMcfe/d) (6) (7)	**170.5**	191.2	(11)	**177.6**	201.4	(12)
Per Trust Unit (cubic feet equivalent/d/Unit) (3)	**1.36**	1.69	(20)	**1.50**	1.81	(17)
Average natural gas prices ($/Mcfe)						
Before financial hedging and physical forward sales (8)	**4.27**	6.84	(38)	**4.26**	8.19	(48)
Including financial hedging and physical forward sales (8)	**5.87**	7.61	(23)	**7.27**	8.18	(11)
RESERVES (Bcfe)						
Company interest – proved (9) (10)	**244.4**	263.6	(7)	**244.4**	263.6	(7)
Company interest - proved and probable (9) (10) (11)	**471.6**	487.1	(3)	**471.6**	487.1	(3)
Per Trust Unit (Mcfe/Unit) (12)	**3.74**	4.31	(13)	**3.74**	4.31	(13)
Estimated present value before tax ($ millions) (11)						
Proved	**834.6**	1,011.4	(17)	**834.6**	1,011.4	(17)
Proved and probable	**1,387.3**	1,642.2	(16)	**1,387.3**	1,642.2	(16)
LAND (thousands of net acres)						
Total land holdings	**3,759**	3,801	(1)	**3,759**	3,801	(1)
Undeveloped land holdings	**2,093**	2,106	(1)	**2,093**	2,106	(1)
DRILLING (wells drilled gross/net)						
Gas	**7/6.5**	24/23.6	(71)/(72)	**50/40.2**	91/75.4	(45)/(47)
Oil	**2/2.0**	-/-	100/100	**2/2.0**	-/-	100/100
Dry	**-/-**	-/-	-/-	**-/-**	2/1.6	(100)/(100)
Total	**9/8.5**	24/23.6	(63)/(64)	**52/42.2**	93/77.0	(44)/(45)
Success Rate	**100/100**	100/100	-/-	**100/100**	98/98	2/2

(1) Revenue includes realized gains and losses on financial instruments and call option premiums received.

(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), excluding short-term financial instrument assets and liabilities related to the Trust’s hedging activities and the current portion of convertible debentures. Total net debt includes convertible debentures, measured at principal amount.

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

(7) Deemed production describes all gas shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the Alberta Energy and Utilities Board (“AEUB”), or through correspondence in relation to an AEUB ID 99-1 application. This deemed production is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen (“GOB”) financial solution received monthly from the Alberta Crown as a reduction of other royalties payable. See “Gas over bitumen royalty adjustments” in Management’s Discussion and Analysis.

(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 contracts during the period were instead sold at AECO monthly index.

(9) As evaluated by McDaniel & Associates Consultants Ltd. (“McDaniel”) in accordance with National Instrument 51-101. See “Reserves” included in this 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 2.3 Bcfe on a proved and probable basis in 2009 (2008 – 3.3 Bcfe).

(11) Discounted at five percent using McDaniel’s forecast pricing. Reserves at various other discount rates are located in the “Reserves” section of Management’s Discussion and Analysis. Includes gas over bitumen royalty adjustments (2009 - $109.9 million, 2008 - $70.5 million) related to the financial solution described in Note 7 above and estimated probable gas over bitumen shut-in reserves (2009 – 45.8 Bcf and $55.3 million, 2008 – 26.6 Bcf and $78.3 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, 2009 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, 2009 and 2008, 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 8, 2010.

Mcf equivalent (Mcfe) and barrel of oil equivalent (BOE) may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a conversion ratio for Mcfe and BOE 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 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, gas over bitumen royalty adjustments not yet received, asset retirement expenditures and certain exploration costs ("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)	**2009**	2008	**2009**	2008
Cash flow provided by operating activities	**36,446**	69,179	**228,352**	259,764
Exploration costs (1)	**646**	3,820	**6,402**	9,178
Settlement of asset retirement obligations	**802**	1,636	**3,715**	5,226
Gas over bitumen royalty adjustments not yet received	**5,138**	-	**5,138**	-
Changes in non-cash operating working capital	**(3,623)**	(13,122)	**(12,260)**	1,266
Funds flow	**39,409**	61,513	**231,347**	275,434
Funds flow per Trust Unit (2)	**0.32**	0.55	**1.96**	2.47

(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, 2009 (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 2009, 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, 2009, 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.

GLOBAL ECONOMIC ENVIRONMENT

Despite experiencing adverse economic conditions in 2009, the elements of PET's cycle-driven business plan allowed the Trust to weather the storm of very low natural gas prices. The Trust significantly increased its attention to manage the balance sheet, increased its downside protection against falling natural gas prices in these uncertain times and implemented measures to preserve the value of the Trust's reserves. The elements of focus in PET's four-pronged business plan were as follows:

- **Maximize cash flow from operations** –The Trust's financial gas hedging portfolio contributed over $166 million of funds flow to PET in 2009, or 72 percent of total funds flow.
- **Asset optimization** – In response to very low natural gas prices, PET reduced its 2009 capital expenditure program to $65 million from an original budget of $113 million. Further, the Trust shut-in approximately 35 MMcfe/d of natural gas production in the spring and summer of 2009. This decision resulted in the conservation of over five Bcf of natural gas reserves. PET returned 20 MMcfe/d to production in October 2009 in anticipation of higher winter gas prices, with the remainder expected to come back on-line in the first quarter of 2010.
- **Accretive acquisitions** – PET acquired Profound Energy Inc. ("Profound") during 2009 for a total purchase price of $113.0 million, including assumed debt. The Profound assets are located primarily within the Trust's new ventures Area in west central Alberta The acquisition represents another step in the strategic expansion of PET's asset base, complementing the Trust's existing shallow gas prospect inventory with a significant number of higher impact, deep-basin style resource play opportunities and significant exposure to the horizontal development of the Pembina tight Cardium oil play.
- **Healthy balance sheet** – The Trust reduced net debt by $19.9 million during 2009, taking into account the assumption of debt associated with the Profound acquisition, and estimates that funds flows for 2010 will be sufficient to fund both distributions and exploration and development spending for the year at current commodity prices.

The Trust has met several significant challenges in its history, including the gas over bitumen shut-in hearings, the federal trust tax legislation and the new Alberta royalty regime, and has persevered despite these obstacles. All four components of the Trust's business plan combine to maximize Unitholder value, and PET's technical and administrative staff are dedicated to this objective, both navigating the challenges and taking advantage of the opportunities presented by the changes in the cyclical business environment.

FOURTH QUARTER 2009 RESULTS

Fourth quarter information	**Three months ended December 31**		
($ thousands except per Trust Unit, per Mcfe and percent amounts)	**2009**	2008	% change
Daily production volumes (MMcfe/d)	**145.9**	173.1	(16)
Oil and natural gas revenues	**56,987**	109,090	(48)
Realized gains (losses) on financial instruments	**20,456**	8,665	136
Call option premiums received	**1,409**	3,408	(59)
Oil and natural gas revenues, after financial instruments	**78,852**	121,163	(35)
AECO Monthly Index ($/Mcf)	**$ 4.23**	$ 6.79	(38)
Natural gas price, before financial hedging and physical forward sales ($/Mcfe)	**$ 4.27**	$ 6.84	(38)
Realized natural gas price ($/Mcfe)	**$ 5.87**	$ 7.61	(23)
Royalties	**2,986**	18,083	(83)
Royalties as a percentage of revenues (%)	**3.8**	14.9	(74)
Operating expenses	**18,970**	26,265	(28)
Per Mcfe	**$ 1.41**	$ 1.65	(15)
Cash general and administrative ("G&A") expenses	**10,105**	9,221	10
Per Mcfe	**$ 0.75**	$ 0.58	29
Funds flow	**39,409**	61,513	(36)
Per Trust Unit	**$ 0.32**	$ 0.55	(42)
Cash flow provided by operating activities	**36,446**	69,179	(47)
Per Trust Unit	**$ 0.29**	$ 0.61	(52)
Net earnings (loss)	**(11,287)**	(8,986)	26
Per Trust Unit	**$ (0.09)**	$ (0.08)	13
Capital expenditures – exploration and development	**10,107**	28,329	(64)

- Production decreased 16 percent to average 145.9 MMcfe/d as compared to 173.1 MMcfe/d for the fourth quarter of 2008 due to voluntary production shut-ins, the shut-in of 10.5 MMcf/d of gas production at Legend as a result of an interim gas over bitumen regulatory shut-in order, non-core asset dispositions in the Northern district and natural production declines. These were partially offset by new production additions from the Trust's 2009 capital programs and the Profound acquisition.

- Realized natural gas prices were 23 percent lower in the fourth quarter of 2009, in contrast to a 38 percent decrease in AECO Monthly Index prices compared to the three months ended December 31, 2008. PET's realized gas price for the current period was 39 percent higher than the AECO Monthly Index price due to the Trust's active natural gas price management program.

- The Trust's royalty rate of 3.8 percent of revenues was 74 percent less than 2008 and lower than the Trust's historical royalty rates due to the decreased royalty rates in the current low gas price environment and $20.5 million in realized gains on financial instruments in the fourth quarter of 2009.

- Cash G&A expenses increased $0.9 million from the fourth quarter of 2008, due to lower overhead recoveries as a result of decreased operating and capital expenditures as compared to the prior period.

- Operating costs decreased $7.3 million due to lower fourth quarter production volumes and a company focus on the reduction of operating costs. Fourth quarter 2009 unit-of-production basis operating costs declined 15 percent to $1.41 per Mcfe.

- Funds flow decreased $22.1 million to $39.4 million for the fourth quarter of 2009 as lower gas prices combined with a decrease in production and the shut-in of the Trust's Legend asset, resulting in a 48 percent drop in revenues before hedging gains. The decrease in revenue was somewhat offset by lower operating costs and royalty expenses.

- Net loss totaled $11.3 million for the three months ended December 31, 2009, as lower funds flows were offset by gains on property sales of $8.3 million. The 2008 fourth quarter loss included $16.1 million in future tax expense, as compared to a recovery of $0.8 million for the current three-month period.

- Capital spending totaled $10.1 million for the fourth quarter, including the drilling of 9 wells (8.5 net wells), including two wells in the Southern district, five wells in the west central district and two wells related to PET's gas storage project, with a 100 percent success rate.

- Distributions for the fourth quarter of 2009 totaled $0.15 per Trust Unit, paid on November 16, 2009, December 15, 2009 and January 15, 2010. PET's payout ratio, which refers to distributions measured as a percentage of funds flow, was 47.7 percent for the quarter.

- PET finished planning and began the execution of a $32 million 2010 winter exploration and development capital program targeting 12 to 15 MMcfe/d of natural gas production additions through drilling, completion, tie-in and facility projects primarily in the Trust's Northern and West Central districts. In addition, PET spent approximately $11 million on further delineation and evaluation of the Trust's gas storage project at Warwick.

ANNUAL RESULTS

($ millions, except volumes and per Trust Unit amounts)	**2009**	2008	2007
Cash flow provided by operating activities	**228.4**	259.8	222.9
Cash flow provided by operating activities per Trust Unit [(2)]	**1.93**	2.33	2.27
Funds flow [(1)]	**231.3**	275.4	239.1
Funds flow per Trust Unit [(1) (2)]	**1.96**	2.47	2.44
Net earnings (loss)	**14.4**	30.8	(32.9)
Distributions	**75.8**	133.9	145.8
Distributions per Trust Unit [(3)]	**0.64**	1.20	1.50
Payout ratio (%) [(1)]	**32.8**	48.6	61.0
Exploration and development expenditures	**68.2**	126.1	118.0
Total capital expenditures	**172.7**	109.2	523.4
Net bank and other debt outstanding at December 31 [(4)]	**270.8**	284.9	335.7
Convertible debentures, measured at principal amount	**230.2**	236.0	236.1
Total net debt at December 31 [(4)]	**501.0**	520.9	571.8
Total net debt per Trust Unit [(4) (6)]	**3.97**	4.61	5.22
Production (MMcfe/d) [(5)]			
Daily average production	**157.7**	182.2	170.2
Gas over bitumen deemed production	**19.9**	19.2	19.9
Total average daily (actual and deemed)	**177.6**	201.4	190.1
Production per Trust Unit (cubic feet equivalent/d/Unit) [(2)]	**1.33**	1.63	1.74
Production per Trust Unit – actual and deemed (cubic feet equivalent/d/Unit) [(2)]	**1.50**	1.81	1.94

(1) These are non-GAAP measures; please refer to "Significant Accounting Policies and Non-GAAP measures" included in this MD&A.
(2) Based on weighted average Trust Units outstanding for the period.
(3) Based on Trust Units outstanding at each cash distribution date.
(4) Net debt is measured as at the end of the period and includes net working capital (deficiency) excluding short-term financial instrument assets and liabilities related to the Trust's hedging activities and the current portion of convertible debentures. Total net debt includes convertible debentures. Please refer to "Significant accounting policies and non-GAAP measures" included in this MD&A.
(5) Production amounts are based on company interest (working interest and royalties receivable) before royalties payable.
(6) Based on Trust Units outstanding at period end.

- Funds flow decreased 16 percent to $231.3 million or $1.96 per Trust Unit in 2009 as compared to $275.4 million or $2.47 per Trust Unit for 2008 due primarily to lower realized natural gas prices and decreased production levels, partially offset by lower royalties and operating expenses.

- PET's average gas price including financial hedging and physical forward sales ("realized" gas price) decreased 11 percent to $7.27 per Mcfe in 2009 from $8.18 per Mcfe in 2008, as compared to a 50 percent decrease in average AECO gas prices for the year. The Trust continued to execute on its proactive natural gas price risk management strategy in 2009, realizing $166 million in gains on financial instruments and $5.7 million in call option premiums and providing a measure of stability to realized prices and funds flows despite significant volatility in natural gas prices.

- Daily average production decreased 13 percent to 157.7 MMcfe/d in 2009 as a result of voluntary well shut-ins, non-core asset dispositions, and gas over bitumen shut-ins in the Legend area in combination with natural production declines. These production impacts were partially offset by the acquisition of the Profound properties in the West Central district and successful capital programs during the year.

- In response to low natural gas prices during 2009, the Trust voluntarily shut in approximately 35 MMcfe/d of natural gas production in the second and early third quarters, leading to a reduction in full year production volumes of 14.7 MMcfe/d.

- PET disposed of non-core assets Athabasca and Saskatchewan for net proceeds of $26.6 million, representing approximately 5.2 MMcfe/d of daily production, as well as 12.7 Bcfe of proved and probable reserves.

- Effective October 31, 2009 the Energy Resources Conservation Board ("ERCB") ordered the shut-in of approximately 8.6 MMcfe/d of natural gas production from the Trust's Legend property due to gas over bitumen concerns. An additional 1.9 MMcfe/d has been shut-in due to the shut in of facilities in the area. As a result of the ERCB order, 12.6 Bcfe of proved reserves related to the Legend property were reclassified to probable by PET's reserve evaluators. PET is eligible to receive the gas over bitumen financial solution in respect of the production by the ERCB order, as prescribed by the royalty regulations enacted by the Alberta government (see "Gas over bitumen royalty adjustments" in this MD&A).

- The Trust acquired Profound in a two-stage transaction in the second and third quarters of 2009 for a total of $27.5 million in cash, 10.0 million PET Trust Units valued at $32.2 million and $53.3 million in assumed net debt of Profound.

- Exploration and development capital spending totaled $68.2 million in 2009, including a $40 million winter capital program focused on activities in the Trust's core areas in the Northern district. The remaining capital expenditures were directed towards PET's year-round access asset base in east central Alberta, drilling activity on Profound lands in the fourth quarter of 2009 and approximately $10.8 million on the preliminary evaluation of the Trust's gas storage project in the Warwick area within the Southern district. In total 49 wells were drilled (41.7 net) with a 100 percent success rate.

- In 2009, the Trust added 38.4 Bcfe of proved reserves and 3.7 Bcfe of probable reserves for total reserve additions of 42.1 Bcfe of proved and probable reserves, excluding production. After production of 57.5 Bcfe in 2009, proved and probable reserves decreased 3 percent from 487.1 Bcfe at year end 2008 to 471.6 Bcfe and proved reserves decreased 7 percent to 244.4 Bcfe at year end 2009. Reserve additions largely offsetting production were due to the successful reinvestment of $68.2 million in exploration and development spending programs, representing approximately 29 percent of the Trust's 2009 funds flow, and acquisitions net of dispositions of $103.9 million.

- Including future development capital and the reclassification of PET's reserves at Legend, PET realized finding, development and acquisition costs of $4.07 per Mcfe ($24.42 per BOE) for proved reserves and $2.41 per Mcfe ($14.46 per BOE) for proved and probable reserves in 2009. Excluding changes in future development capital, finding, development and acquisition costs for the year totaled $4.48 per Mcfe ($26.88 per BOE) for proved reserves and $4.09 per Mcfe ($24.54 per BOE) for proved and probable reserves.

- As a result of funds flows in excess of distributions and capital expenditures, minor non-core property dispositions and including the assumption of $53.3 million of Profound net debt, PET reduced net bank debt by five percent from $284.8 million at December 31, 2008 to $270.8 million at December 31, 2009. Including PET's convertible debentures of $230.2 million, total net debt dropped from $520.9 million at December 31, 2008 to $501.0 million at December 31, 2009.

- PET declared cash distributions of $75.8 million or $0.64 per Trust Unit in 2009, representing 32.8 percent of funds flow for the year. Cumulative distributions from the inception of the Trust to year-end 2009 totaled $1.03 billion ($13.764 per Trust Unit).

- Net earnings totaled $14.4 million in 2009 as compared to $30.8 million in 2008, as lower funds flows were partially offset by reductions in depletion and future tax expenses compared to prior year.

OPERATIONS

Properties

PET's legacy asset base is highly focused on shallow natural gas in Northeast and east central Alberta. The vast majority of PET's shallow gas properties feature well established, high working interest production and most are operated by PET. The Trust's base production profile is predictable due to the lengthy production histories and the large number of independent producing entities in 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. Competitive 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 including workovers, uphole recompletions and a risk concentric inventory of drilling prospects which extends throughout the shallow gas 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 provides additional opportunities to add value through synergies and economies of scale.

In recent years PET has consciously moved to reposition its asset base to enhance its prospect inventory, adding an element of higher impact, growth oriented, resource-style opportunities to its asset portfolio. In 2008 the Trust successfully added the Elmworth Montney play to its prospect inventory through grass roots exploration, and signed a farmout agreement with an industry partner on these lands in 2009 in order to accelerate development and mitigate exploration risk. In 2009, PET executed a major step in the strategic expansion of its asset base with the Profound acquisition, to add a component of deep basin, resource-style properties to its asset base as well as to gain exposure to the developing Cardium tight oil play in the Pembina area of Alberta.

PET's producing assets are 96 percent natural gas and concentrated in north and central Alberta.

Northern District

The Northern District is comprised of PET's legacy gas producing assets transferred with its spin out from Paramount Resources Ltd. in 2003 and has been complemented with consolidating and operationally synergistic asset acquisitions. Generally access for capital activities is restricted to winter-only. This Northern District largely overlaps the Athabasca Oil Sands area and the Trust has also amassed a material inventory of oil sands leases for future development that will require a variety of subsurface recovery technologies.

Northeast – The Northeast area is PET's largest core area measured by production and total acreage, and is comprised primarily of the original assets acquired from Paramount Resources at the inception of the Trust in 2003. Significant areas of production in this core area include Liege, Saleski, Woodenhouse, Cold Lake, Craigend and Leismer. Production is primarily from the Devonian Grosmont and various overlying Cretaceous formations. The majority of the shut-in gas related to the gas over bitumen issue is in the Wabiskaw-McMurray formation in this area. Production at Legend was shut-in on October 31, 2009 as a result of an interim ERCB shut-in order related to a gas over bitumen dispute with oil sands owners in the area. The Trust has bitumen leases in this area at Liege, Ells, Clyde and Saleski.

Athabasca - Athabasca includes assets south and west of the Trust's original spin-out assets in the Northeast area. Production is from multiple stratigraphic horizons including Cretaceous clastic and Devonian carbonate reservoirs. Significant gas producing properties in this core operating area include Calling Lake, Darwin, Marten Hills, Mitsue, Panny, Peter Lake and Wabasca/Hoole. PET also owns significant bitumen leases at Panny, Wabasca Lake and Marten Hills.

Southern District

Natural gas in the Southern District is from a base of varied assets with geological characteristics similar to the Northern District assets, but with the added advantage of having year-round access. Production in this multi-zoned potential area is from over ten different Cretaceous or Devonian aged reservoirs and consists of both conventional and tight unconventional shallow gas reservoirs.

Birchwavy West - Warwick, Bruce and Killam areas of central Alberta are the major producing properties in this core area. A significant inventory of proved and probable undeveloped reserves is present in this area targeting a resource-style play in the Viking formation.

Birchwavy East - Production from the Birchwavy East area is primarily from Colony channel reservoirs in the Cretaceous Mannville zone as well as other conventional Mannville sand reservoirs. In addition, unconventional, tight, shallow gas resource play potential from the Viking and Colorado group formations extend across these assets. It includes the largest properties in the area, Mannville and Duvernay.

West Central District

The strategic focus on growth in west central Alberta was initiated in 2008 with the purchase of a significant exploration position for Montney gas in the Elmworth area south of Grande Prairie. PET established a joint venture with an industry partner at Elmworth in 2009 to mitigate exploration and execution risk. The Trust expects that three wells will be drilled in 2010 to evaluate the economic viability of the Montney gas development. In 2009, PET successfully completed the acquisition of Profound to add the Pembina area and further establish the West Central district. Production includes light crude oil and liquids-rich natural gas, and is approximately 25 percent liquids. The West Central lands complement the Trust's existing shallow gas prospect inventory with a significant number of higher impact, deep basin style resource play opportunities, including acreage along the Cardium trend, which has recently become an active target for development with horizontal wells and multi-stage fracture stimulation. The growth potential in the Cardium oil play is a platform for further diversification of commodity price risk.

Severo Energy Corporation

In 2006, to facilitate development of minor assets in the Athabasca core area, Paramount Energy Trust transferred certain assets in the Radway area to a private company, Severo Energy Corporation ("Severo"). Paramount Energy Trust has an indirect ownership of 93 percent in Severo. Production in Severo's core area is primarily derived from the Second White Specks, Colony, Viking, Glauconite, Ellerslie and Wabamum formations. Severo's business strategy concentrates on continued growth in the core area of Big Bend/Radway through re-completions, low risk drills and synergistic consolidating acquisitions, as well as the pursuit of higher impact exploration prospects outside of the Big Bend/Radway core area.

Production

Natural gas production by core area (MMcfe/d)	**2009**	2008	2007
Northern district			
Northeast (1) (2)	**57.5**	68.9	72.2
Athabasca (1)	**41.8**	52.5	56.8
Northern district total	**99.3**	121.4	129.0
Southern district (1)			
Birchwavy West	**16.4**	22.6	12.4
Birchwavy East	**28.0**	29.5	18.7
Southern district total	**44.4**	52.1	31.1
West Central district (4)	**7.5**	-	-
Severo	**5.5**	7.0	6.3
Other	**1.0**	1.7	3.8
Total (3)	**157.7**	182.2	170.2
Deemed production (2) (5)	**19.9**	19.2	19.9
Total actual plus deemed production	**177.6**	201.4	190.1
Voluntary production shut-ins (3)	**14.7**	-	-

(1) In 2009 the Trust consolidated certain core areas in order to increase operating and general and administrative efficiencies. The Northeast core area combines the East Side and West Side areas, while the East Central district has been moved from the Southern district to the Northern district and included with Athabasca. Prior period production figures have been reclassified to conform to the current presentation.

(2) Effective October 31, 2009 the ERCB ordered the shut-in of approximately 8.6 MMcf/d of natural gas production from the Trust's Legend property in the Northeast core area due to gas over bitumen concerns. PET shut in an additional 1.9 MMcf/d of gas production due to the shut-in of facilities in the area.

(3) 2009 average production was reduced by approximately 14.7 MMcfe/d as a result of voluntary production shut-ins initiated in a number of producing areas in the Northern, West Central and Southern districts to preserve value during this period of low gas prices.

(4) Production from the West Central district is attributable to the Profound acquisition, which closed on June 30, 2009. The West Central district averaged production of 15.0 MMcfe/d since the acquisition date.

(5) Deemed production is a result of gas over bitumen shut-in production volumes in the Northeast core area. See "Gas over bitumen royalty adjustments" in this MD&A.

With the significant downturn in natural gas prices in 2009, PET undertook a detailed analysis of the economic attributes of all of its properties in order to identify opportunities to preserve value through voluntary production curtailments. There was an expected gain in present value through the deferral of production until prices stabilized. Production deferral had the additional benefit of preserving reserves and the related lending value under the Trust's bank credit facility. Not all properties were suitable candidates for temporary shut-in due to operational considerations, fixed operating cost levels, and processing, joint venture and transportation arrangements. As a result of this analysis, the Trust shut in approximately 35 MMcfe/d of natural gas production in spring and summer 2009, leading to a reduction in full year production volumes of 14.7 MMcfe/d. The Trust returned 20 MMcfe/d of shut-in volumes to production in the fourth quarter of 2009 due to strengthening in natural gas prices associated with the winter heating season.

PET expects that the remainder of the shut-in production will be brought back onstream in the first quarter of 2010.

Production volumes decreased 13 percent to 157.7 MMcfe/d in 2009 from 182.2 MMcfe/d in 2008. The decrease is primarily due to voluntary production shut-ins, non-core asset dispositions, the regulatory shut-in of production at Legend and natural declines, partially offset by the acquisition of Profound and a successful 2009 winter capital program.

In 2009, 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, Duvernay in the Birchwavy East core area, accounting for ten percent of the total production. By comparison, in 2008 the five largest properties represented 32 percent of PET's total production with the largest property, Wabasca representing seven percent. This diversification of production minimizes the risk that operating problems at a specific property will materially impact the Trust.

Profound acquisition

On June 30, 2009, pursuant to a takeover offer announced on March 31, 2009, the conversion of previously issued special warrants and open market purchases, PET acquired 67.3 percent of the outstanding common shares and thereby gained control of Profound Energy Inc. ("Profound"). On August 13, 2009, PET completed the second stage of the announced transaction, acquiring the remaining 32.7 percent of Profound's outstanding shares. Cash consideration paid for Profound consisted of $6.9 million for the special warrants, $3.1 million for the open market share purchases and $14.2 million for the tendered shares on June 30, 2009 and August 13, 2009, and $3.3 million of acquisition costs for a total of $27.5 million. In addition, PET issued 10.0 million Trust Units to Profound shareholders valued at $32.2 million, using PET's weighted average unit trading price for the five trading days surrounding the announcement date of $3.21 per Trust Unit.

Capital expenditures

Capital expenditures ($ thousands)	2009	2008	2007
Exploration and development expenditures [1]	**64,263**	99,512	109,933
Crown and freehold land purchases	**3,908**	26,579	8,025
Acquisitions	**17,436**	5,706	450,576
Profound acquisition – cash consideration	**27,536**	-	-
Profound acquisition – Trust unit consideration [2]	**32,184**	-	-
Profound acquisition – assumption of net debt	**53,309**	-	-
Dispositions	**(26,580)**	(24,220)	(46,408)
Other	**649**	1,588	1,254
Total capital expenditures	**172,705**	109,165	523,380

(1) Exploration and development expenditures for 2009 include approximately $6.4 million in exploration costs which have been expensed directly on the Trust's statement of earnings (2008 - $9.2 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.

(2) Trust unit consideration for the Profound acquisition consisted of 10.0 million Trust Units issued at a value of $3.21 per Trust Unit, using PET's weighted average unit trading price for the five trading days surrounding the acquisition announcement date.

Exploration and development expenditures measured $64.3 million in 2009 as compared to $99.5 million for 2008. PET completed a successful winter capital program in northeast Alberta in the first quarter of 2009, investing $40 million in new drilling, recompletion, workover and facilities optimization work primarily in the Trust's winter-access only core areas in northeast Alberta. With the significant drop in natural gas prices in spring and summer of 2009, PET chose to restrict capital spending for the remainder of 2009 to strategic and land-preserving expenditures only. These capital expenditures for the second half of 2009 were directed towards PET's year-round access asset base in east central Alberta, drilling activity on Profound lands in the fourth quarter of 2009 and approximately $10.8 million on the preliminary evaluation of the Trust's gas storage project in the Warwick area within the Southern district.

Land acquisitions totaled $3.9 million in 2009, a $22.7 million decrease from 2008 levels. Prior year expenditures included the acquisition of several large parcels of exploratory acreage in west central Alberta for $19.1 million. PET significantly enhanced its prospect inventory in 2009 through the Profound acquisition, which had approximately 89,000 net undeveloped acres in west central Alberta, offering exposure to several highly prospective oil and natural gas resource plays, including 54 net sections in the Cardium light oil fairway at Carrot Creek and Cochrane. These lands were valued at $15.9 million by PET on the acquisition date, and are included in the acquisition price.

Dispositions totaled $26.6 million in 2009 compared to $24.2 million in 2008. Properties sold in 2009 were primarily non-core assets in Athabasca and Saskatchewan. The disposed properties represented approximately 5.2 MMcfe/d of daily production, as well as 12.7 Bcfe of proved and probable reserves.

The Board of Directors of Paramount Energy Operating Corp., PET's administrator, has approved a capital expenditure budget of $80 million for 2010, including crown and freehold land purchases. A $32 million winter capital program is largely complete while capital expenditures for the remainder of the year can be adjusted depending on natural gas prices, as deemed appropriate. The budget excludes up to $40 million of capital for the Trust's Warwick natural gas storage project which will be financed by the forward sale of cushion gas in the storage reservoir. PET expects to spend approximately $11 million on the gas storage project in the first quarter of 2010 on the delineation drilling phase of the project and preparation for facility construction.

Drilling

	2009		2008		2007	
Wells drilled	**Gross**	**Net**	Gross	Net	Gross	Net
Gas	**46**	**36.2**	91	75.4	129	103.2
Oil	**2**	**2.0**				
Gas storage	**4**	**4.0**	-	-	-	-
Dry	**-**	**-**	2	1.6	8	7.2
Total	**52**	**42.2**	93	77.0	137	110.4
Success rate (%)	**100**	**100**	98	98	94	93

PET drilled 42.2 net wells in 2009 as compared to 77.0 wells in 2008. Drilling activity in 2009 included 24 (18.2 net) wells spread throughout the Trust's three core areas in the Northern district, 19 (16.0 net) wells in the Southern district, three (3.0 net) wells in the West Central district, including two oil wells, and four wells (4.0 net) as part of the preliminary evaluation of PET's gas storage project. Severo drilled two wells (1.0 net) in 2009.

Reserves

PET's complete National Instrument 51-101 ("NI 51-101") reserves disclosure as at December 31, 2009 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, 2009.

The reserves data set out below (the "Reserves Data") is based wholly upon an evaluation by McDaniel and Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2009 contained in a report of McDaniel dated January 31, 2010 (the "McDaniel Report"). McDaniel's evaluation covers 100 percent of the Trust's oil and natural gas 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 96 percent of the Trust's reserves are natural gas, volumes are presented on a Mcf equivalent basis. PET reports the results of the Trust's 93 percent-owned subsidiary 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)	**2009**	2008	2007
Proved			
Developed producing	**202,757**	210,855	231,339
Developed non-producing	**8,293**	13,621	16,598
Undeveloped	**33,322**	39,138	46,843
Total proved	**244,372**	263,615	294,780
Probable producing, non-producing and undeveloped	**181,398**	196,793	187,818
Shut-in gas over bitumen [(1)]	**45,806**	26,648	27,308
Total probable	**227,204**	223,441	215,126
Total proved & probable	**471,576**	487,055	509,907
Trust Units outstanding (millions)	**126.2**	113.0	109.6
Total proved & probable per Trust Unit (Mcfe/Unit)	**3.74**	4.31	4.65

(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.

PET's proved and probable reserves to production ratio, also referred to as reserve life index ("RLI") was 8.8 years at year-end 2009 while the proved RLI was 4.8 years, based on 2010 production estimates in the McDaniel report. The Trust's proved and probable RLI at December 31, 2008 was 7.5 years, while the proved RLI was 4.5 years.

McDaniel's price forecast utilized in the evaluation is summarized below.

McDaniel January 1, 2010 Price Forecast

Year	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Natural Gas at AECO ($Cdn/MMBtu)	Foreign Exchange ($US/$Cdn)
2010	80.00	83.20	6.05	0.950
2011	83.60	87.00	6.75	0.950
2012	87.40	91.00	7.15	0.950
2013	91.30	95.00	7.45	0.950
2014	95.30	99.20	7.80	0.950
2015	99.40	103.50	8.15	0.950
2016	101.40	105.60	8.40	0.950
2017	103.40	107.70	8.55	0.950
2018	105.40	109.80	8.70	0.950
2019	107.60	112.10	8.90	0.950
2020	109.70	114.30	9.05	0.950
2021	111.90	116.50	9.25	0.950
2022	114.10	118.80	9.45	0.950
2023	116.40	121.20	9.65	0.950
Escalate thereafter at	2%	2%	2%	0.950

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 at December 31 ($ millions)	**0%**	**5%**	**2009** **10%**	0%	5%	2008 10%	0%	5%	2007 10%
Proved									
Developed producing	**784.3**	**654.6**	**569.5**	1,008.7	845.7	739.2	967.5	806.0	704.1
Developed non-producing [(1)]	**17.6**	**14.0**	**11.9**	9.8	14.2	14.8	(0.4)	9.4	11.4
Gas over bitumen royalty adjustments	**129.9**	**109.9**	**94.9**	79.6	70.5	63.2	88.9	77.5	68.5
Undeveloped	**77.2**	**56.0**	**41.1**	112.5	81.0	58.8	114.0	79.1	55.1
Total proved	**1,009.0**	**834.5**	**717.4**	1,210.6	1,011.4	876.0	1,170.0	972.0	839.1
Probable									
Developed and undeveloped	**727.2**	**497.4**	**359.9**	797.4	552.5	405.9	655.2	440.3	317.5
Shut-in gas over bitumen reserves [(2)]	**100.3**	**55.3**	**32.3**	123.1	78.3	51.7	112.3	68.7	44.4
Total probable	**827.5**	**552.7**	**392.2**	920.5	630.8	457.6	767.5	509.0	361.9
Total proved & probable	**1,836.5**	**1,387.2**	**1,109.6**	2,131.1	1,642.2	1,333.6	1,937.5	1,481.0	1,201.0
Trust Units outstanding (millions)	**126.2**	**126.2**	**126.2**	113.0	113.0	113.0	109.6	109.6	109.6
Total proved & probable per Trust Unit ($/Unit)	**14.55**	**10.99**	**8.79**	18.86	14.53	11.80	17.68	13.51	10.96

(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 ten percent discount factor, the proved producing reserves including gas over bitumen royalty adjustments comprise 59.9 percent of the proved and probable value while total proved reserves account for 64.7 percent of the proved and probable value at December 31, 2009. Further, proved and probable developed producing reserves account for 74.4 percent of the proved and probable value at December 31, 2009.

After-tax reserve amounts from the McDaniel report using forecast prices and costs are shown below.

After-tax net present values as at December 31, 2009	**Total proved**		**Total proved and probable**	
($ millions, discounted at 0% and 10%)	**0%**	**10%**	**0%**	**10%**
Net present value, before taxes	1,009.0	717.4	1,836.5	1,109.6
Income taxes	(106.4)	(75.1)	(305.4)	(176.8)
Net present value, after taxes	**902.6**	**642.3**	**1,531.1**	**932.8**

The McDaniel Report assumes the utilization of PET's current existing tax pools plus additions from future development costs, beginning in 2010 with taxation of after-tax cash flow at corporate income tax rates beginning in 2012.

The following table sets forth a reconciliation of the changes in reserves for the year ended December 31, 2009 from the opening balance on December 31, 2008 derived from the McDaniel Reports at those dates, using McDaniel forecast prices.

Reserves reconciliation (Bcfe)	Proved	Probable	Proved & Probable
December 31, 2008	263.7	223.4	487.1
Discoveries and extensions	13.8	4.6	18.4
Technical revisions	7.1	(24.4)	(17.3)
Transfer of shut-in gas over bitumen to probable	(12.6)	12.6	-
Acquisitions, net of dispositions	32.8	13.4	46.2
Production	(57.5)	-	(57.5)
Economic factors	(2.9)	(2.4)	(5.3)
December 31, 2009	**244.4**	**227.2**	**471.6**

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 changes in FDC.

FD&A costs – company interest reserves ($ millions except where noted)	**Proved**	**Proved (excluding shut-in gas over bitumen)[(1)]**	**Proved and Probable**	**Proved and Probable (excluding gas storage project)[(2)]**
FD&A costs excluding future development capital				
Exploration and development capital expenditures	68.2	68.2	68.2	57.4
Acqusitions, net of dispositions	103.9	103.9	103.9	103.9
FD&A capital expenditures	172.1	172.1	172.1	161.3
Reserve additions including net acquisitions (Bcfe)	38.4	50.9	42.1	40.6
Finding, development and acquisition cost ($/Mcfe) [(3)]	4.48	3.38	4.09	3.97
FD&A costs including future development capital				
FD&A capital expenditures	172.1	172.1	172.1	161.3
Total change in FDC	(15.9)	(15.9)	(70.5)	(70.5)
Total FD&A capital including change in FDC	156.2	156.2	101.6	90.8
Reserve additions including net acquisitions (Bcfe)	38.4	50.9	42.1	40.6
Finding development and acquisition cost including FDC - $/Mcfe [(3)]	4.07	3.07	2.41	2.24

(1) 12.6 Bcfe of proved gas reserves in the Legend area were shut in and transferred to probable reserves due to ERCB Interim Shut In Order 09-003.

(2) Capital expenditures related to the preliminary assessment of a gas storage project in the Warwick area of east central Alberta in 2009 of $10.8 million have been excluded.

(3) Differences in FD&A costs from the Trust's press release dated February 9, 2010 are due to adjustments related to the finalization of PET's 2009 year-end audited financial statements.

FD&A costs including FDC are lower than FD&A costs excluding FDC due to a reduction in future capital in the Trust's reserve report from the previous year, as a result of technical reductions to unconventional reserves in the Southern district and general decreases in industry costs for drilling and completing new wells.

Land

	2009		2008		2007	
Land inventory	**Net acres**	**Average working interest (%)**	Net acres	Average working interest (%)	Net acres	Average working interest (%)
Developed	**1,666,352**	**68.0**	1,694,944	65.9	1,689,182	65.4
Undeveloped	**2,092,637**	**83.1**	2,106,021	81.1	2,000,768	80.3
Total	**3,758,669**	**75.6**	3,800,965	73.6	3,689,950	72.8

PET's undeveloped net acreage position remained relatively unchanged in 2009, as lease expiries and disposed acreage was fully offset by undeveloped land purchased through land sales and acquisitions, including the Profound acquisition (89,142 net acres). PET has the most extensive inventory of undeveloped land in the energy trust sector relative to its production and reserves base.

The Trust's undeveloped acreage in the East Side Core Area includes approximately 327,000 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. Further, the Trust now has in inventory a total of 326,000 net acres of oil sands leases.

The fair market value of PET's undeveloped acreage is internally estimated to be $143 million at December 31, 2009 (December 31, 2008 - $141 million), using a combination of average land sale values by area and the cost of recent land purchases by the Trust. Decreases in fair values resulting from the disposition of acreage in Saskatchewan and Athabasca was more than offset by the prospective lands in west central Alberta obtained through the Profound acquisition, which have been valued at $15.9 million.

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 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. Actual results will differ materially from the assumptions mandated by NI 51-101, as these do not reflect the full potential value of the Trust's extensive prospect inventory.

Of particular note, there are no reserves assigned to the Trust's Elmworth Montney project or to PET's prospective Pembina Cardium tight oil play which will be evaluated through planned drilling activity in 2010. In addition, no reserves or contingent resources are yet assigned to any of PET's heavy oil projects in northeast Alberta. The value of PET's prospect inventory is reflected only in the estimated fair market value of undeveloped land based on current land sale valuation parameters.

PET has developed internal data analysis tools to rigorously manage its prospect inventory. In addition to prospects to develop proved and probable undeveloped reserves captured in the reserve report, the Trust's prospect inventory contains over 700 uphole recompletion opportunities, in excess of 500 conventional drilling locations proximal to its northeast and east central Alberta assets, multiple horizontal and vertical drilling prospects targeting gas in west central Alberta as well as a risk-discounted prospect inventory to develop the Trust's larger scope resource play opportunities in the Montney at Elmworth, tight Cardium oil in west central Alberta, additional shallow shale gas in the Viking and Colorado in eastern Alberta and several of its nearer term prospective heavy oil assets. PET runs its business on a going-concern basis, investing in opportunities to add value, improve profitability and increase reserves in an effort to enhance the Trust's net asset value beyond the amounts shown in its annual reserve evaluation.

Pre-tax net asset value at December 31, 2009[1]				**Discounted at**
($ millions except where noted)	**Undiscounted**	**5%**	**8%**	**10%**
Total proved and probable reserves[2]	$ 1,836	$ 1,387	$1,188	1,110
Fair market value of undeveloped land[3]	143	143	143	143
Net bank debt[6]	(271)	(271)	(271)	(271)
Convertible debentures[6]	(230)	(230)	(230)	(230)
Estimate of additional future abandonment and reclamation costs[4] [6]	(108)	(66)	(50)	(42)
Mark to McDaniel's value of PET's forward hedging[5]	53	51	50	49
Net asset value	**$ 1,423**	**$ 1,014**	**$ 830**	**$ 759**
Trust Units outstanding (million)	126	126	126	126
Net asset value per Trust Unit ($/Unit)	$ 11.29	$ 8.05	$ 6.59	$6.02

(1) Financial information is per PET's 2009 audited consolidated financial statements.
(2) Reserve values per McDaniel Report as at December 31, 2009.
(3) Internal estimate. See "Land" in this MD&A.
(4) Amounts are net of salvage value and in addition to amounts in the McDaniel Report for future well, pipeline and facility abandonment costs related to developed reserves. See "Asset retirement obligation" in this MD&A.
(5) Value of PET's open hedging transactions at year end 2009 assuming settlement against the McDaniel price forecast.
(6) Differences in net debt, convertible debentures and abandonment and reclamation costs from the Trust's press release dated February 9, 2010 are due to adjustments related to the finalization of PET's 2009 year-end audited financial statements.

PET's three year history of net asset value and net asset value per Trust Unit, discounted at five percent and including distributions paid to Unitholders, is as follows.

Pre-tax net asset value at December 31, discounted at 5%			
($ millions except per unit amounts)	**2009**	**2008**	**2007**
Net asset value	**1,014**	1,201	1,250
Net asset value per Trust Unit ($/Unit)	**8.05**	10.63	11.41
Distributions per Trust Unit ($/Unit)	**0.64**	1.20	1.50
Net asset value per Trust Unit including distributions paid ($/Unit)	**8.69**	11.83	12.91

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. In order to independently assess 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, some of which may require external financing.

At inception of the Trust in February 2003, based on the value of year-end 2002 reserves discounted at five percent and adjusted upward for the Trust's hedging and the forward gas price strip at the time, the NAV was determined to be $8.91 per Trust Unit. Since that time, including the December 2009 distribution paid on January 15, 2010, the Trust has distributed $13.764 per Trust Unit. Despite having distributed $4.854 per Trust Unit more in cash distributions than the initial NAV, the NAV as at December 31, 2009 dropped only marginally to $8.05 per Trust Unit using a five percent discount rate.

MARKETING

Natural gas prices

Natural gas price ($/Mcfe, except percentages)	2009	2008	2007
Reference prices			
AECO Monthly Index	**4.14**	8.13	6.61
AECO Daily Index	**3.98**	8.15	6.49
Alberta Gas Reference Price (1)	**3.85**	7.88	6.21
Average PET prices			
Before financial hedging and physical forward sales (2)	**4.26**	8.19	6.44
Percent of AECO Monthly Index	**103**	101	97
Before financial hedging (3)	**4.28**	8.15	6.64
Percent of AECO Monthly Index	**103**	100	100
Including financial hedging and physical forward sales (“Realized” natural gas price)	**7.27**	8.18	7.44
Percent of AECO Monthly Index	**176**	101	113

(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, as well as selling forward financial call options to counterparties. 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 monthly 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 in Louisiana, while western Canada natural gas prices are referenced to the AECO Hub in Alberta. AECO Monthly Index prices decreased 49 percent to average $4.14 per Mcf in 2009 as compared to $8.13 per Mcf for 2008, while AECO Daily Index prices decreased 51 percent year over year. The economic recession had a significant adverse impact on the demand for natural gas in 2009 which, coupled with an increase in supply due largely to new shale gas discoveries in North America, resulted in the AECO Monthly Index price falling from $6.56 per Mcf in January 2009 to $2.69 per Mcf in September. This trend reversed course late in the year as the global economic recovery and seasonal heating increased natural gas demand and led to an increase in the AECO Monthly Index from its September low to $4.78 per Mcf in December 2009.

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 51 percent from $7.88 per Mcf in 2008 to $3.85 per Mcf in 2009, consistent with the decrease in AECO monthly and daily index prices.

PET’s average realized gas price was $7.27 per Mcfe in 2009, down 11 percent from $8.18 per Mcfe in 2008. The decrease in realized prices was much less than the decrease in AECO prices from year to year due to $166.3 million in realized hedging gains and $5.7 million in call option premiums received in 2009. PET’s natural gas price before financial hedging and physical forward sales decreased 48 percent to $4.26 per Mcfe in 2009 from $8.19 per Mcfe in 2008, in line with the decrease in AECO prices for the year.

Hedging and risk management

PET’s gas price 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 capital programs and acquisitions and to take advantage of perceived anomalies in natural gas markets. The Trust uses both financial hedge arrangements and physical forward sales to hedge up to a maximum of 60 percent of the trailing quarter’s production including gas over bitumen deemed volumes in accordance with the limits under the Trust’s credit facility and hedging and risk management policies. 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 perception of the 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, 2009, please see note 11 to the annual consolidated financial statements as at and for the year ended December 31, 2009. PET continued to supplement its risk management program after the end of the year, including the crystallization of approximately $57 million in gains in respect of the Trust's March to October 2010 hedging portfolio in February and March of 2010. The hedge price on the crystallized volumes for the April to October 2010 period was reset to $4.55 per GJ. Financial and physical natural gas forward sales positions (net of related financial and physical fixed-price natural gas purchase contracts) at March 8, 2010 are as follows.

Type of Contract	Volumes at AECO(2) (GJ/d)	% of 2010 Budgeted Volume(4)	Price(1) ($/GJ)	Futures Market(3) ($/GJ)	Term
Financial	90,000	46	4.55	4.31	April – October 2010
Financial	85,000		7.83		November 2010 – March 2011
Physical	10,000		7.75		November 2010 – March 2011
Period Total	95,000	49	7.82	5.13	November 2010 – March 2011
Financial	30,000	15	6.28	5.01	April – October 2011
Financial	89,679	46	6.78	6.01	January – March 2013

(1) Average price calculated using weighted average price for sell contracts.
(2) All transactions are at AECO unless identified specifically as a NYMEX transaction.
(3) Futures market reflects AECO/NYMEX forward market prices as at March 8, 2010.
(4) Calculated using 194,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes and voluntary production shut-ins.

PET has also entered into a financial collar arrangement. The collar consists of 1,000 GJ/d with a floor of $5.00/GJ and a ceiling of $7.55 per GJ for the term January 2010 to March 2010.

As part of PET's risk management strategy, the Trust has also sold forward financial call options to counterparties to purchase natural gas from PET at strike prices in excess of current forward prices. Option premiums of $10.7 million have been received and included in funds flows in respect of these transactions, of which $3.4 million relates to 2008, $5.7 million relates to 2009 and $1.6 million relates to the first quarter of 2010. Call option contracts outstanding as of March 8, 2010 are as follows.

Type of Contract	Volumes at AECO (GJ/d)	% of 2010 Budgeted Volume (2)	Strike Price ($/GJ)(1)	Futures Market(3) ($/GJ)	Term
Sold Call	6,000	3	8.34	5.08	January – March 2010
Sold Call	20,000	10	7.25	4.64	January – December 2010
Sold Call	15,000	8	7.08	4.31	April – October 2010
Sold Call	32,500	17	8.00	5.13	November 2010 – March 2011
Sold Call	25,000	13	6.00	5.01	April – October 2011

(1) Weighted average prices are calculated by netting the volumes of the lowest-priced financial and physical sold/bought contracts together and measuring the net volume at the weighted average "sold" price for the remaining financial and physical contracts.
(2) Calculated using 194,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes and voluntary production shut-ins.
(3) Futures market reflects AECO/NYMEX forward market prices as at March 8, 2010.

The Trust also enters 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. PET had no net basis exposure as of March 8, 2010.

FINANCIAL RESULTS

Revenue

Revenue ($ thousands)	**2009**	2008	2007
Oil and natural gas revenue, before financial instruments (1)	**246,243**	543,576	412,571
Realized gains (losses) on financial instruments (2)	**166,340**	(1,283)	49,838
Call option premiums received (3)	**5,740**	3,408	-
Total oil and natural gas revenue	**418,323**	545,701	462,409

(1) Includes revenues related to physical forward sales contracts which settled during the period.
(2) Realized gains (losses) on financial instruments include settled financial forward contracts.
(3) Call option premiums received classified separately on the Trust's statement of earnings and are included in the calculation of the Trust's realized gas price and funds flows. The changes in mark-to-market value of the options from period to period are included in unrealized gains (losses) on financial instruments in the statement of earnings.

Oil and natural gas revenue in 2009 was $418.3 million, representing a 23 percent decrease from $545.7 million in 2008. The decrease in revenue was a function of the 11 percent decrease in the Trust's average realized gas price in 2009 as compared to the prior year and a 13 percent decrease in production from 2008 to 2009.

Included in realized gains on financial instruments in 2009 is $37.0 million in financial instrument gains related to early termination of certain fixed-price forward natural gas contracts for post-2009 periods (2008 - $10.4 million).

The Trust recorded unrealized gains on financial instruments of $7.8 million in 2009, reflecting the change in the fair value of unsettled financial and physical forward natural gas and foreign exchange contracts during the year.

Funds flow

	2009		2008		2007	
Funds flow reconciliation	**$ millions**	**($/Mcfe)**	$ millions	($/Mcfe)	$ millions	($/Mcfe)
Production volume (Bcfe)	**57.5**		66.7		62.1	
Revenue (1)	**418.3**	**7.27**	545.7	8.18	462.4	7.44
Royalties	**(17.4)**	**(0.30)**	(92.3)	(1.38)	(64.8)	(1.04)
Operating costs	**(105.1)**	**(1.83)**	(120.6)	(1.81)	(102.6)	(1.65)
Transportation costs	**(11.7)**	**(0.20)**	(14.1)	(0.21)	(12.7)	(0.20)
Operating netback from production	**284.1**	**4.94**	318.7	4.78	282.3	4.55
Gas over bitumen royalty adjustments	**10.4**	**0.18**	20.8	0.31	17.3	0.28
Lease rentals	**(4.2)**	**(0.07)**	(3.5)	(0.05)	(3.5)	(0.06)
General and administrative (2)	**(32.1)**	**(0.56)**	(31.9)	(0.48)	(24.7)	(0.40)
Interest and other (2)	**(11.9)**	**(0.21)**	(13.7)	(0.20)	(19.5)	(0.34)
Interest on convertible debentures (2)	**(15.0)**	**(0.26)**	(15.0)	(0.23)	(12.8)	(0.21)
Funds flow (2) (3)	**231.3**	**4.02**	275.4	4.13	239.1	3.82

(1) Revenue includes realized gains (losses) on financial instruments and call option premiums received.
(2) Excludes non-cash items.
(3) This is a non-GAAP measure, see "Significant Accounting Policies and Non-GAAP Measures" in this MD&A.

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, which are based on processing fees and allowable capital costs incurred at a property and are in accordance with Crown royalty regulations. Crown royalty rates tend to decrease with decreases in the Alberta Gas Reference Price, and rise as the reference price increases.

The effective royalty rate applicable to the Trust in 2009 was 4.2 percent (2008 – 16.9 percent) or $0.30 per Mcfe (2008 - $1.38 per Mcfe). The decrease in royalty rate was primarily due to the fact that the Alberta Gas Reference price decreased 51 percent from year to year, while the Trust's realized natural gas price only decreased 11 percent. PET's realized gas price measured 188 percent of the Alberta Gas Reference price for 2009. PET's 2009 royalty rate, measured as a percentage of oil and gas revenues before financial instruments, decreased to 7.1 percent from 17.0 percent in 2008, due to lower Alberta Gas Reference Prices during the current period, as well as the new royalty framework implemented by the Alberta government on January 1, 2009, partially offset by higher royalty rates on production from the Profound assets as compared to PET's asset base.

In 2009 the Government of Alberta announced a new incentive program designed to increase industry activity despite low oil and natural gas prices and tightened credit markets caused by the global financial crisis. The program was effective April 1, 2009, and offered two separate incentives:

- A $200 per metre drilling royalty credit for new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, available to companies on a sliding scale based on company production levels from 2008.

- A maximum five percent royalty rate for the first year of production from new oil or gas wells, subject to a maximum annual production of 50,000 bbl or 500,000 Mcf. The maximum rate applies to all wells which begin production after March 31, 2009 and before April 1, 2011.

PET realized $1.6 million in drilling royalty credits through 2009 drilling activity, which have been recorded as a reduction to property, plant and equipment on the Trust's balance sheet, and a reduction to capital expenditures on the statement of cash flows.

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 $105.1 million ($1.83 per Mcfe) in 2009 as compared to $120.6 million ($1.81 per Mcfe) in 2008. In 2009 PET implemented cost reduction initiatives at all operated fields to enhance competitiveness, profitability and efficiency, leading to a decrease in operating costs of $15.5 million from 2008 levels. Unit-of-production costs increased marginally due to lower production levels and increased property taxes and other fixed costs related to the ongoing operation and maintenance of facilities and other infrastructure, including areas where production was voluntarily shut-in for economic reasons.

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 separately recorded as transportation costs for the product. Alberta's gas transportation system operates on a postage stamp basis. PET has reduced costs relative to the postage stamp costs through the execution of direct sales arrangements with end users of natural gas proximal to the Trust's producing fields in northeast Alberta. Total transportation costs decreased by 17 percent to $11.7 million in 2009 from $14.1 million in 2008, in line with the decrease in production levels from year to year. On a unit-of-production basis, transportation costs decreased by $0.01 per Mcfe to $0.20 per Mcfe compared to $0.21 per Mcfe in 2008.

Operating netbacks

A 13 percent decrease in production levels and an 11 percent decrease in the Trust's realized natural gas price were the primary drivers in decreasing PET's operating netback by $34.6 million to $284.1 million for the year ended December 31, 2009 from $318.7 million for the prior year. Despite the decrease in the Trust's gas price, on a unit-of-production basis the operating netback increased by three percent from $4.78 in 2008 to $4.94 per Mcfe in 2009 due to lower royalty rates.

Operating netback reconciliation ($ millions)	
Realized price decrease	(74.8)
Production decrease	(52.6)
Royalty decrease	74.9
Operating cost decrease	15.5
Transportation decrease	2.4
Decrease in operating netback	(34.6)

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, or its successor agency the Energy Resources Conservation Board ("ERCB") 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)	**2009**	2008	2007
Average deemed volume (MMcf/d)	**19.9**	19.2	19.9
Gas price	**3.85**	7.88	6.21
Royalties	**(0.77)**	(1.58)	(1.24)
Operating costs	**(0.40)**	(0.40)	(0.40)
50% reduction factor	**(1.34)**	(2.95)	(2.28)
Gas over bitumen royalty adjustment netback	**1.34**	2.95	2.29

The Trust's net deemed production volume for purposes of the royalty adjustment was 19.9 MMcf/d for 2009. 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 increased by 0.7 MMcf/d from the 19.2 MMcf/d recorded for 2008 as a result of the shut-in of the Trust's Legend property in the Northeast core area effective November 1, 2009, partially offset by the annual ten percent reduction in deemed production volumes discussed previously. Current deemed production is approximately 28.7 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 2009 PET disposed of certain shut-in gas wells in the gas over bitumen area for proceeds of $1.5 million. As part of the disposition agreement the ownership of the natural gas reserves was transferred to the buyer and as such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer PET's responsibility, nor does the Trust retain the right to future gas over bitumen royalty adjustments. As a result of this disposition, the gas over bitumen royalty adjustments received to the date of the disposition by the Trust, for the affected wells, are now considered revenue since they will not be repaid to the Crown. As a result the Trust reclassified $1.2 million in previous gas over bitumen royalty adjustments from the balance sheet to the statement of earnings.

In 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.

Gas over bitumen royalty adjustments are not paid to PET in cash, but are a deduction from the Trust's monthly natural gas royalty invoices. In periods of exceptionally low gas prices, such as those experienced in the second half of 2009, the Trust's net crown royalty expenses are close to zero, and as such the royalty adjustments are not received immediately. Eventual realization of the royalty adjustments is highly likely as deemed production is reduced by ten percent annually, whereas the Trust is focused on maintaining production and reserves year over year through capital spending programs, complemented with strategic acquisitions. PET has a total of $5.1 million in royalty adjustments receivable as at December 31, 2009, which are netted against the gas over bitumen liability on the Trust's balance sheet. These amounts are included in funds flows and considered distributable income. The change in PET's gas over bitumen liability during 2009 is as follows.

Gas over bitumen royalty adjustments ($ thousands)	
Net liability, December 31, 2008	74,643
Royalty adjustments recorded for 2009	7,662
Less: royalty adjustments not yet received	(5,138)
Net liability, December 31, 2009	**77,167**

Lease rentals

Lease rentals reflect annual payments made to the Alberta Crown or other land owners in order to maintain the rights to explore previously-acquired undeveloped acreage. These payments are expensed by the Trust in accordance with the successful efforts method of accounting for oil and gas assets, whereas they are typically capitalized by companies employing the full cost method of accounting. Lease rentals increased from $3.5 million in 2008 to $4.2 million in 2009. In 2008 PET leased out a portion of its undeveloped fee-simple acreage to third parties; a portion of the proceeds received were credited to lease rentals.

General and administrative expenses

		2009		2008		2007
	$000's	**$/Mcfe**	$000's	$/Mcfe	$000's	$/Mcfe
Cash general & administrative	**32,134**	**0.56**	31,955	0.48	24,670	0.40
Trust Unit-based compensation [1]	**7,481**	**0.13**	5,671	0.09	4,287	0.07
Total general & administrative	**39,615**	**0.69**	37,626	0.57	28,957	0.47

[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 largest 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 producing properties and capital projects are recorded as a reduction of G&A expenses, and are a function of capital and operating expenditures during the year, as well as the Trust's productive well base.

Cash G&A expenses, net of overhead recoveries on operated properties, increased marginally to $32.1 million from $32.0 million in 2008. The increase is largely due to $1.8 million in additional costs related to the management of the Profound assets, offset by the benefits of PET's corporate cost reduction initiatives initiated early in 2009. The increase in cash G&A is also partially due to lower overhead recoveries as compared to 2008 due to the decrease in operating and capital expenditures in the current year, and a decrease in the number of producing wells due to the voluntary and ERCB-ordered shut-ins during the year. G&A expenses increased on a unit-of-production basis from $0.57 per Mcfe in 2008 to $0.69 per Mcfe in 2009 due to lower production volumes caused primarily by voluntary production shut-ins.

Trust Unit-based compensation increased by $1.8 million ($0.04 per Mcfe) in 2009, related to a $2.1 million charge recorded in the third quarter for the cancellation of 2.5 million unit incentive rights. Compensation expense is calculated on unit incentive rights at the time of issue using a binomial option pricing model, and is not adjusted for subsequent changes in the value of the incentive rights as a result of changing market conditions.

Prior to January 1, 2011, PET plans to take advantage of SIFT conversion rules which allow the Trust to simplify its organizational structure as it converts to a corporation. PET expects that G&A expense in 2010 will be impacted by approximately $1.0 million in costs related to the Trust's conversion. These will be disclosed separately in the Trust's MD&A, but included with G&A expenses in PET's consolidated financial statements.

Interest expense

Interest and other expense decreased to $11.9 million in 2009 from $13.8 million in 2008 as a result of a decrease in short-term interest rates on the Trust's credit facility to an average of 3.8 percent in 2009 from 4.3 percent in the prior period, as well as a 13 percent decrease in average long-term bank debt from year to year.

In 2009, $18.2 million of interest on convertible debentures was expensed as compared to $18.3 million in 2008. Included in interest on convertible debentures for 2009 is $3.2 million of non-cash expenses related primarily to the amortization of debt issue costs (2008 - $3.3 million). On September 30, 2009, the remaining $5.6 million of 8% convertible debentures issued in 2004 matured and were repaid by the Trust in cash.

Funds flow

Lower gas over bitumen royalty adjustments combined with lower production levels resulted in funds flow netbacks decreasing three percent from $4.13 per Mcfe in 2008 to $4.02 per Mcfe in 2009, despite higher operating netbacks per Mcfe for the year. Funds flow decreased to $231.3 million ($1.96 per Trust Unit) for the year ended December 31, 2009 from $275.4 million ($2.47 per Trust Unit) in the 2008 period, as result of the decrease in production and natural gas prices, partially offset by lower royalties and operating costs. The 55 percent decline in natural gas revenues before financial instruments in 2009 compared to 2008 was mitigated by $166 million in realized gains related to PET's hedging portfolio, limiting the decrease in funds flow to 16 percent year over year.

Exploration expense

Exploration costs include lease rentals paid on undeveloped lands, seismic expenditures, amortization expense on undeveloped land and expired leases and are expensed by the Trust in accordance with the successful efforts method of accounting for oil and gas assets, whereas they are typically capitalized by companies employing the full cost method of accounting. Exploration expenses totaled $21.8 million in 2009 as compared to $34.1 million in 2008, due to lower seismic expenditures in 2009, partially offset by higher land amortization expense in the Northern district. Prior year exploration expense includes an impairment charge of $12.0 million related to a decrease in fair market value of the Trust's undeveloped land in certain core areas in the Northern district. For the purpose of the impairment test on undeveloped properties, fair values are derived from recent average land sale prices in each core area and are not necessarily indicative of the potential opportunities on the Trust's land base, many of which have already been identified in PET's prospect inventory.

Depletion, depreciation and accretion

PET's 2009 depletion, depreciation and accretion ("DD&A") rate increased to $3.44 per Mcfe from $3.28 per Mcfe in 2008. In 2009, successful efforts accounting rules changed to require DD&A to be calculated based on "average price" reserves, which are measured using the average commodity price on the first trading day of each month of the year. Prior to 2009 reserves were evaluated using a constant price as of the last trading day of the year. For DD&A purposes, the Trust's 2009 reserves were evaluated using an average natural gas price of $3.79 per Mcf. The low price resulted in lower reserve volumes than the forecast price reserves disclosed above, which increased the Trust's DD&A rate. PET also recorded an impairment charge of $5.0 million related to a non-core property group outside of the Trust's two primary operating districts, which is included in DD&A for the current period, as compared to an impairment charge of $2.7 million recorded in 2008. PET 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 also includes accretion expense on the asset retirement obligation of $13.7 million in 2009 as compared to $13.9 million in 2008. The slight decrease in accretion, despite the acquisition of Profound in June 2009, is due to PET's increasing reserve life and property dispositions during the year.

Depletion, depreciation and accretion

($ thousands except per Mcfe amounts)	**2009**	2008	2007
Depletion expense	**183,952**	204,638	209,496
Accretion of asset retirement obligation	**13,738**	13,904	10,672
Total	**197,690**	218,542	220,168
Per unit-of-production ($/Mcfe)	**3.44**	3.28	3.54

At year-end 2009, property, plant and equipment costs include $120.5 million (2008 - $126.8 million) currently not subject to depletion and $73.4 million (2008 - $26.8 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. The $46.6 million increase in gas over bitumen costs is due to the shut-in of the Legend property in the Northeast Core Area effective November 1, 2009.

Asset retirement obligation

PET estimates its total future asset retirement obligation based on net ownership interest in all wells, facilities and pipelines, including estimated costs to abandon the wells, facilities and pipelines and reclaim the sites and the estimated timing of the costs to be incurred in future periods. Pursuant to this evaluation, the estimated undiscounted total value of PET's future asset retirement obligations is $343 million as at December 31, 2009. As at December 31, 2009, the undiscounted net salvage value of the Trust's gas plants, compressors and facilities was estimated at $127 million. The McDaniel Report includes an undiscounted amount of $138 million with respect to expected future well abandonment costs related specifically to proved and probable reserves and such amount is included in the values captioned "Total proved and probable reserves" in the "NPV of reserves" table in this MD&A. Of the total future well abandonment costs included in the McDaniel Report an undiscounted amount of $108 million relates to PET's developed reserves.

The following table presents the estimated future asset retirement obligations and estimated net salvage values at various discount rates.

			Discounted at	
Abandonment and reclamation costs ($ millions)	**0%**	**5%**	**8%**	**10%**
Well abandonment costs for developed reserves included in McDaniel Report	108	75	62	55
Well abandonment costs for undeveloped reserves included in McDaniel Report	30	15	10	8
Well abandonment costs for total proved and probable reserves included in McDaniel Report	138	90	72	63
Estimate of other abandonment and reclamation costs not included in McDaniel Report (2)	205	133	106	92
Total estimated future abandonment and reclamation costs (2)	**343**	**223**	**178**	**155**
Salvage value	(127)	(82)	(66)	(58)
Abandonment and reclamation costs , net of salvage	**216**	**141**	**112**	**97**
Well abandonment costs for developed reserves included in McDaniel Report	(108)	(75)	(62)	(55)
Estimate of additional future abandonment and reclamation costs, net of salvage (1) (2)	108	66	50	42

(1) Future abandonment and reclamation costs not included in the McDaniel Report, net of salvage value.

(2) Differences from the Trust's press release dated February 9, 2010 are due to adjustments related to the finalization of PET's 2009 year-end audited financial statements.

The asset retirement obligation presented in PET's financial statements is discounted using an estimate of the timing of asset retirement expenditures and PET's estimated credit-adjusted discount rate, which is reviewed and adjusted annually for changes in credit markets and other internal and external factors. These expenditures are currently expected to occur over the next 25 years with the majority of costs incurred between 2015 and 2020. PET's discounted asset retirement obligation increased from $179.7 million at December 31, 2008 to $194.6 million at December 31, 2009 primarily due to abandonment liabilities acquired with the Profound acquisition and accretion expense for the year.

Income taxes

In 2007, legislation was passed (the "Trust Tax Legislation") pursuant to which certain distributions from publicly-traded specified investment flow through entities ("SIFTs"), including energy trusts, 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 the Trust's 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. PET has a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be ten percent, which would result in an effective tax rate of 26.5 percent in 2011 and 25 percent in 2012.

In 2008 the Department of Finance provided guidelines to enable the conversion of existing income trusts and other SIFT entities into public corporations without immediate tax consequences to the SIFTs or their investors. The amendments will allow such conversions from that date until 2013. The proposals generally facilitate the conversion of SIFTs into corporations and reflect the government's intention to permit SIFTs to convert to corporate status on a tax-deferred basis while mitigating undue tax effects.

A variety of operational, tax and other factors need to be weighed in determining when and how PET will adjust its business and legal structure. PET is currently analyzing potential structures and courses of action and although the Trust has not yet made a final determination with respect to future changes in the structure of its business operations, it anticipates these changes to be in effect prior to December 31, 2010.

PET recorded future tax expense of $0.4 million for 2009 (2008 – $16.1 million). Based on production forecasts for PET's reserves included in the independent reserve report as at December 31, 2009, and funds flows based on current forward AECO prices for natural gas, the book values of the Trust's assets are projected to exceed the related tax values on January 1, 2011, the date the direct tax on distributions within the Trust becomes effective. Future income tax is a non-cash expense and does not affect the Trust's funds flows or its cash available for distributions.

Tax pools

Tax pool information ($ millions)	As at December 31, 2009
Canadian oil and gas property expense (COGPE)	291
Canadian development expense (CDE)	130
Canadian exploration expense (CEE)	63
Undepreciated capital cost (UCC)	179
Trust unit issue costs	11
Non-capital losses	134
Total	808

At December 31, 2009, the Trust's consolidated income tax pools are estimated to be $808 million. Tax pools increased during 2009 as a result of the Profound acquisition. Actual tax pool amounts will vary as tax returns are finalized and filed.

Net earnings

Net earnings totaled $14.4 million or $0.12 per basic and diluted Trust Unit in 2009 as compared to net earnings of $30.8 million or $0.28 per basic Trust Unit ($0.27 per diluted Trust Unit) in 2008, as a result of lower oil and natural gas revenue offset partially by lower royalties, operating costs and DD&A expenses.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Capitalization and financial resources		Year ended December 31	
($ thousands except per Trust Unit and percent amounts)	**2009**	2008	2007
Long term bank debt	**262,393**	276,976	342,190
Convertible debentures, measured at principal amount	**230,168**	236,034	236,109
Working capital deficiency (surplus) [(2)]	**8,450**	7,859	(6,519)
Net debt	**501,011**	520,869	571,780
Trust Units outstanding at end of period (thousands)	**126,224**	112,968	109,557
Market price at end of period	**5.22**	5.05	6.30
Market value of Trust Units	**658,889**	570,488	690,209
Total capitalization [(1)]	**1,159,900**	1,091,357	1,261,989
Net debt as a percentage of total capitalization (%)	**43.2**	47.7	45.3
Annualized fourth quarter funds flow [(1)]	**157,636**	246,052	238,488
Net debt to funds flow ratio (times) [(1)]	**3.2**	2.1	2.4

(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 and the current portion of convertible debentures.

PET has a demand credit facility with a syndicate of Canadian chartered banks. The revolving feature of the facility expires on May 24, 2010 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 $360 million, comprised of a $345 million production component and a $15 million working capital component. The next borrowing base redetermination is scheduled for May 10, 2010. 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 (excluding Severo) in respect of amounts borrowed under the facility. Bank debt decreased to $262.4 million at December 31, 2009, as compared to $277.0 million at December 31, 2008 as funds flows exceeded distributions and exploration and development expenditures. In addition to amounts outstanding under the credit facility PET has outstanding letters of credit in the amount of $13.0 million.

Severo has a separate credit facility with a Canadian chartered bank in the amount of $10 million. The facility is due on demand, and the borrowing base is reviewed annually in April. Collateral for the facility is provided by a floating charge covering all property of Severo. As of December 31, 2009, Severo had drawn $7.6 million on the facility. Due to the demand nature of the facility, all related borrowings are classified as current liabilities on the Trust's balance sheet.

PET has a working capital deficiency of $8.5 million at December 31, 2009, as compared to a deficiency of $7.9 million at December 31, 2008. The negative working capital in both periods is primarily related to the classification of the Severo credit facility as a current liability. The Trust's working capital deficiency will be funded from future sales revenues and by additional borrowings from PET's credit facility, as required.

Net debt as a percentage of total capitalization decreased to 43.2 percent at year-end 2009 as compared to 47.7 percent in the prior year, as a result of an increase in market capitalization during the year. Net debt to annualized fourth quarter funds flow increased to 3.2 times for the three months ended December 31, 2009 from 2.1 times for the three months ended December 31, 2008 due to lower funds flows. A reconciliation of the change in net debt from December 31, 2008 to December 31, 2009 is as follows.

Reconciliation of net debt ($ millions)	
Net debt, December 31, 2008	520.9
Capital expenditures (exploration and development and other)	68.8
Acquisitions, net of dispositions (excluding Trust Unit component of Profound Acquisition)	71.7
Funds flow	(231.3)
Distributions	75.8
Proceeds from DRIP plan	(14.2)
Proceeds from exercise of unit incentive rights	(0.5)
Issue fees for convertible debentures	1.0
Gas over bitumen royalty adjustments not yet received	5.1
Expenditures on asset retirement obligations	3.7
Net debt, December 31, 2009	**501.0**

The Trust expects that its distributions and capital expenditure program for 2010 will be funded by funds flow. 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	2010	2011-2012	2013-2014	Thereafter
Bank and other debt [1]	270.0	7.6	262.4	-	-
Convertible debentures, principal	230.2	55.3	74.9	-	100.0
Operating leases [3]	17.8	2.6	4.8	4.0	6.4
Pipeline commitments [2]	15.2	6.4	5.8	2.8	0.2
Total contractual obligations	533.2	71.9	347.9	6.8	106.6

(1) The revolving feature of PET's credit facility expires on May 24, 2010 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. Severo's credit facility is a demand loan.

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

(3) PET has office leases on its current office space, and on Profound's office space. Profound office lease commitments are shown net of related sublease recoveries.

Convertible debentures

As at December 31, 2009, the Trust had 6.5 percent convertible debentures issued in June 2007 (6.5% Debentures), 7.25 percent convertible debentures issued in April 2006 (7.25% Debentures) and 6.25 percent convertible debentures issued in April 2005 (6.25% Debentures) outstanding.

Convertible debentures series ($ millions, except as noted)	6.50%	7.25%	6.25%
Principal issued	75.0	100.0	100.0
Principal outstanding	74.9	100.0	55.3
Maturity date	June 30, 2012	January 31, 2015	June 30, 2010
Conversion price ($ per Trust Unit)	14.20	7.50	19.35
Fair market value	74.9	105.0	55.3

On December 17, 2009 the 7.25% Debentures were amended as follows:

- Interest rate increased from 6.25 percent to 7.25 percent
- Conversion price reduced to $7.50 per Trust Unit from $23.80 per Trust Unit
- Maturity date extended to January 31, 2015 from April 30, 2011

The Trust incurred $1.0 million in fees in connection with the amendments, which has been netted against the carrying amount of the debentures on the balance sheet and will be amortized over the amended life of the debentures.

The Trust has $55.3 million of convertible debentures outstanding that mature on June 30, 2010. There are a number of options available to PET to refinance these debentures, including an issuance of Trust Units or a new series of convertible debentures, repayment of the debentures using draws on the Trust's credit facility, or an issuance of term debt to markets in either Canada or the United States.

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, 2009 by the quoted market price per debenture at that date.

Unitholders' equity

PET's total capitalization was $1.2 billion at December 31, 2009 with the market value of the Trust Units representing 56.8 percent of total capitalization. During 2009, the closing market price of the Trust Units ranged from $2.71 to $5.81 with an average daily trading volume of 373,368 Trust Units.

Weighted average Trust Units outstanding for 2009 totaled 118.2 million (2008 – 111.5 million). On December 31, 2009 there were 126.2 million Trust Units outstanding.

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 $75.8 million ($0.64 per Unit) in 2009 representing 32.8 percent of annual funds flow, bringing total cumulative distributions since inception to year-end 2009 to $1.03 billion ($13.764 per Trust Unit). In 2008, declared cash distributions were $133.9 million ($1.20 per Trust Unit), representing 48.6 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. Monthly distributions were adjusted to $0.07 per Trust Unit in January 2009 and then to $0.05 per Trust Unit in March 2009 to preserve sustainability and strengthen PET's balance sheet in light of weaker natural gas prices and an uncertain economic climate. 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 volatility in 2009.

PET announced on September 21, 2009 that it has adopted a Premium Distribution™ component in its Distribution Reinvestment Plan (the "Premium DRIP") in connection with the September 2009 cash distribution. This Plan supersedes, amends and restates in its entirety the Distribution Reinvestment and Optional Trust Unit Purchase Plan of PET dated December 17, 2003 (the "Original Plan"). The primary differences between the Premium DRIP and the Original Plan are the addition of the Premium Distribution™ component under the Premium DRIP and the discontinuation of the optional Trust Unit purchase component which was available under the Original Plan.

The Premium DRIP allows eligible Unitholders to elect, under the distribution reinvestment component of the Premium DRIP, to have their monthly cash distributions reinvested in additional Trust Units on the applicable distribution payment date. Participants in the distribution reinvestment component of the Premium DRIP will have the ability, as was the case with the Original Plan, to purchase Trust Units with distribution proceeds at a price per Trust Unit equal to 94 percent of the Average Market Price (as defined in the Premium DRIP). The Premium DRIP also allows eligible Unitholders to otherwise elect, under the Premium Distribution™ component of the Premium DRIP, to have these additional Trust Units delivered to the designated Plan Broker in exchange for a premium cash payment equal to 102% of the cash distribution such Unitholders would otherwise have received on the applicable distribution payment date. In the event that eligible Unitholders elect to participate in the Premium Distribution™ component of the Premium DRIP, the additional Trust Units delivered to the designated Plan Broker will be issued from treasury at a five percent discount to the Average Market Price. Canaccord Capital Corporation will act as the Plan Broker for the Premium Distribution™ component of the Premium DRIP.

No commissions, service charges or brokerage fees are payable in connection with the purchase of Trust Units from PET under either component of the Premium DRIP. All administrative costs of the Premium DRIP will be paid by PET. Unitholders who wish to participate in the Premium DRIP indirectly through the brokers, investment dealers, financial institutions or other similar nominees through which their Trust Units are held should consult such nominees to confirm whether commissions, service charges or other fees are payable.

PET anticipates that distributions and development capital expenditures for 2010 will be funded by funds flow; 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)	**2009**	2008
Cash flows provided by operating activities	**228,352**	259,764
Net earnings (loss)	**14,393**	30,785
Distributions	**75,838**	133,921
Excess of cash flows provided by operating activities over distributions	**152,514**	125,843
Shortfall of net earnings over distributions	**(61,445)**	(103,136)

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 $152.5 million (2008 - $125.8 million) compares to exploration and development expenditures per the Trust's statement of cash flows of $61.8 million for the year ended December 31, 2009 (2008 - $116.9 million). The excess of cash flows provided by operating activities over distributions increased in 2009 as compared to 2008 as PET 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 additional bank borrowings and external financing activities as appropriate.

The Trust had an excess of distributions over net earnings in 2009 and 2008, and distributions are likely to continue to exceed net earnings in future periods. PET does not typically compare distributions to earnings due to the 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 2009 cash distributions

Cash distributions are comprised of a return of capital portion (tax deferred) and a return on capital portion (taxable). PET has elected to minimize its tax pool claims in 2009 and, as such, cash distributions received or receivable by a Canadian resident, outside of a registered pension or retirement plan in the 2009 taxation year, are 100 percent taxable.

2009 Distributions by month ($ per Trust Unit) **Payment Date**	**Canadian Taxable Amount**	**Canadian Tax Deferred Amount (Return of capital)**	**Total Distribution**
February 17, 2009	0.07	0.00	0.07
March 16, 2009	0.07	0.00	0.07
April 15, 2009	0.05	0.00	0.05
May 15, 2009	0.05	0.00	0.05
June 15, 2009	0.05	0.00	0.05
July 15, 2009	0.05	0.00	0.05
August 17, 2009	0.05	0.00	0.05
September 15, 2009	0.05	0.00	0.05
October 15, 2009	0.05	0.00	0.05
November 16, 2009	0.05	0.00	0.05
December 15, 2009	0.05	0.00	0.05
January 15, 2010	0.05	0.00	0.05
Total (1)	**0.64**	**0.00**	**0.64**
Percent of distribution	**100**	**0**	**100**

(1) Total is based upon cash distributions declared during 2009.

SUMMARY OF QUARTERLY RESULTS

				Three months ended
($ thousands except where noted)	**Dec 31, 2009**	Sept 30, 2009	June 30, 2009	Mar 31, 2009
Oil and natural gas revenues before royalties (1)	**56,987**	47,875	58,631	82,750
Natural gas production (MMcfe/d)	**145.9**	152.4	165.5	167.1
Funds flow (2)	**39,409**	59,599	91,186	41,154
Per Trust Unit - basic	**0.32**	0.49	0.81	0.36
Net earnings (loss)	**(11,287)**	(44,151)	(8,728)	78,559
Per Trust Unit - basic	**(0.09)**	(0.36)	(0.08)	0.70
- diluted	**(0.09)**	(0.36)	(0.08)	0.69
Realized natural gas price ($/Mcfe)	**5.87**	7.51	9.10	6.46
Average AECO Monthly Index price ($/Mcf)	**4.23**	3.02	3.66	5.63

				Three months ended
($ thousands except where noted)	Dec 31,2008	Sept 30, 2008	June 30, 2008	Mar 31, 2008
Oil and natural gas revenues before royalties (1)	109,090	149,216	166,199	121,878
Natural gas production (MMcfe/d)	173.1	183.7	188.4	183.8
Funds flow (2)	61,513	76,380	81,350	56,191
Per Trust Unit - basic	0.55	0.68	0.73	0.51
Net earnings (loss)	(8,986)	180,796	(55,365)	(85,660)
Per Trust Unit - basic	(0.08)	1.62	(0.50)	(0.78)
- diluted	(0.08)	1.60	(0.50)	(0.78)
Realized natural gas price ($/Mcfe)	7.61	8.78	9.00	7.29
Average AECO Monthly Index price ($/Mcf)	6.79	9.25	9.35	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.

Oil and natural gas revenues are a function of production levels and natural gas prices. Revenues were highest in the second and third quarters of 2008 when AECO Monthly Index prices are highest, averaging $9.30 per Mcf, and lowest in the third quarter of 2009, when the AECO Monthly Index price averaged $3.02 per Mcf. The Trust uses financial instruments to mitigate the effect of volatility in AECO prices on funds flows, and therefore funds flows will trend with PET's realized gas price and changes in production levels. Funds flows were highest in the second quarters of 2008 and 2009 as a result of realized gas prices of $9.00 and $9.10 per Mcfe, respectively. Funds flows are lowest in the fourth quarter of 2009 due to lower realized gas prices coupled with the effects of declining production relative to previous quarters.

Due to the volatility of natural gas prices and the Trust's hedging position, net earnings (losses) will fluctuate with changes in AECO gas prices as of each balance sheet date. Net earnings were exceptionally high in the third quarter of 2008 and first quarter of 2009, as a result of unrealized gains on financial instruments of $168.9 million and $95.1 million, respectively. The net losses in the first and second quarters of 2008 and the third quarter of 2009 were due to unrealized losses of $79.3 million, $70.4 million and $45.8 million, respectively on the change in mark-to-market value of PET's financial instruments during those periods. The net loss in the fourth quarter of 2009 is due to lower funds flows as compared to prior quarters and a substantial increase in the Trust's DD&A rate, as a result of changes to successful efforts accounting rules surrounding reserves used for depletion calculations.

2010 OUTLOOK AND SENSITIVITIES

Approximately $32 million will have been expended on exploration and development activities by the end of the first quarter with positive results thus far, generating approximately 15 to 17 MMcfe/d of production which is expected to come onstream by early April.

PET was active in the Carrot Creek area during the winter season, drilling six gross (5.2 net) vertical wells targeting tight gas sands. All six wells have been cased, for a 100 percent success rate. Three of the wells have been completed with final test rates of 800 Mcf/d, 2,200 Mcf/d and 4,000 Mcf/d plus associated liquids of approximately 30 to 40 bbls per MMcf/d. The remaining three wells are currently undergoing or awaiting completion operations, and five of the six wells are expected to be on production prior to breakup.

Also in the Carrot Creek/Pembina area, a non-operated horizontal oil well (0.5 net) is currently being drilled targeting the Cardium formation, with completion results expected by the end of March. Warm winter weather and an early spring break-up may delay the completion to the second quarter of 2010. PET is also preparing to drill two horizontal Cardium oil wells immediately after breakup. Should the results of this activity be consistent with the positive industry results on neighboring acreage, PET will review its 2010 capital budget and may incorporate an extensive multiwell pad development program at Carrot Creek in the fourth quarter of 2010.

In the Elmworth area, PET and its partner are preparing to drill three horizontal (1.5 net) Montney gas wells, with the first well expected to spud in July 2010. PET will be carried for its 50 percent share of the capital costs for these three wells.

The Trust has increased its focus on growth opportunities in 2010, with plans in place to exploit several of its opportunities in the Montney formation at Elmworth, the Cardium formation at Carrot Creek and Pembina, the shallow Colorado and Viking shale gas play in east central Alberta and two heavy oil opportunities in northeast Alberta. With success in these resource plays, PET is evolving its sustainable distribution model that balances short term cash returns to its Unitholders and long term value creation through capital reinvestment to incorporate a component of repeatable growth.

PET also closed an acquisition of natural gas assets in the Southern district in January 2010 for total proceeds of approximately $17.5 million, including a $1.8 million deposit paid in 2009, which is expected to add 4 MMcfe/d to the Trust's annual average production volumes. In addition, PET has spent approximately $11 million on further delineation and evaluation of the Trust's gas storage project at Warwick.

PET continued to supplement its gas price risk management program in 2010, including the crystallization of approximately $57 million in gains in respect of the Trust's March to October 2010 hedging portfolio in February and March of 2010. The hedge price on the crystallized volumes for the April to October 2010 period was immediately reset to $4.55 per GJ. For April through December 2010 PET has an average of 86 MMcf/d of natural gas production hedged at an average price of $5.59 per Mcf. For January 2011 through October 2011 PET has an average of 46 MMcf/d of gas production hedged at an average price of $7.55 per Mcf.

At current AECO average settled and forward prices of $4.64 per GJ for 2010 the Trust estimates 2010 cash flow of $170 to $180 million. PET has a proactive gas price risk management strategy in place that has resulted in downside protection to this cash flow with financial instruments in place to manage gas price risk for over 50 percent of its 2010 forecast sales and gas over bitumen deemed production volumes. Incorporating PET's current hedging portfolio and forward natural gas prices into the Trust's production, operations and funds flow projections, the current level of distribution represents a payout ratio of approximately 40 to 45 percent for 2010. The current monthly distribution level and planned $80 million exploration and development expenditure program can be funded completely through funds flow, with the additional $10 to $20 million of forecast cash flow directed to reduce bank debt or to increase capital spending on PET's Cardium tight oil play in the Pembina area of west central Alberta. In addition, PET anticipates approximately $40 million in DRIP proceeds for 2010 will further reduce bank indebtedness by year end 2010, assuming participation in the Trust's DRIP and Premium DRIP programs continues at the current level of approximately 60 percent.

The following table shows PET's estimate of key measures for 2010 based on its hedging portfolio, production levels and the Trust's estimated exploration and development capital expenditures and targeted results for full year 2010 under several different full year 2010 AECO gas price assumptions.

	Average full year AECO monthly index gas price ($/GJ) [3]		
Funds flow outlook	$4.00	$5.00	$6.00
Oil and natural gas production (MMcfe/d)	151	151	151
Realized gas price ($/Mcfe)	6.32	6.84	7.36
Funds flow [1] ($ millions)	165	185	201
Per Trust Unit [1] ($/Unit/month)	0.109	0.122	0.132
Payout ratio [1] [4] (%)	46	41	38
Ending net debt ($ millions)	469	448	433
Ending net debt to funds flow ratio [2] (times)	2.8	2.4	2.2

(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 AECO settled and forward price for 2010 as at March 8, 2010 was $4.64 per GJ.
(4) Estimated payout ratio assumes a distribution rate of $0.05 per month per Trust Unit for January through December 2010.

Below is a table that shows sensitivities of PET's 2010 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			
Natural gas price at AECO	$0.25 per Mcf	0.033	0.003
Interest rate on debt	1%	0.021	0.002
Operational			
Production volume	5 MMcfe/d	0.071	0.006
Operating costs	$0.10 per Mcfe	0.043	0.004
Cash general and administrative expenses	$0.10 per Mcfe	0.043	0.004

The Trust's outlook and sensitivities assume operating costs of $2.00 per Mcfe, cash general and administrative expenses of $0.60 per Mcfe, an interest rate on bank debt of 3.8 percent and incorporate the Trust's financial and physical forward sales portfolio at March 8, 2010. Cash general and administrative expenses are equal to general and administrative expenses before Trust Unit-based compensation.

Conversion to Corporation

The Board of Directors of Paramount Energy Operating Corp., the Administrator of PET, unanimously approved the conversion of the Trust to a corporation which, subject to approval of PET's Unitholders as well as customary court and regulatory approvals, is anticipated to be completed at the Annual General Meeting of the Trust scheduled for June 17, 2010. The principal reason for the decision to convert from a trust structure to a corporation is the change in Canadian tax law whereby the government will begin imposing taxes on income trusts on January 1, 2011.

Following a thorough analysis of the various strategic alternatives with respect to PET's structure going forward as well as PET's current Unitholder base, PET has concluded that the proposed conversion will provide broadened access to capital markets by putting the constraints of the SIFT structure imposed by the new tax legislation behind us. In addition, Canadian taxable PET Unitholders will benefit from a more tax effective treatment of their cash dividends following the conversion to a corporate structure. PET Unitholders will also benefit from a simplified and more efficient corporate structure and under the current legislation the conversion can be structured on a tax deferred basis for Canadian income tax purposes. The details of the conversion will be contained in an information circular which is anticipated to be mailed to unitholders in May 2010.

Following the conversion it is anticipated that a monthly dividend of $0.05 per Trust Unit per month will be paid, consistent with PET's current distribution policy. Subject to future fluctuations in commodity prices and other operational variables, and potential changes to capital requirements as PET continues to add to and develop the growth-oriented portion of its asset base, PET intends to continue to maintain a $0.05 monthly dividend for the foreseeable future prior to and following conversion to a corporation.

The corporate conversion will be subject to receipt of all required regulatory, stock exchange and Court of Queen's Bench of Alberta approvals including approval of at least 66 ⅔ percent of the votes by Unitholders present in person or by proxy at a meeting of the Trust's Unitholders.

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.

Net debt

Net debt is measured as bank debt including net working capital (deficiency) excluding short-term financial instrument assets and liabilities related to the Trust's hedging activities and the current portion of convertible debentures. Total net debt includes convertible debentures, measured at principal amount. Net debt and total net debt are used by management to analyze leverage. Net debt and total net debt do not have any standardized meaning prescribed by Canadian GAAP and therefore these terms may not be comparable with the calculation of similar measures for other entities.

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.

NEW ACCOUNTING STANDARDS

Goodwill and Intangible Assets

In February 2008, the CICA issued section 3064, "Goodwill and Intangible Assets," which will replace CICA section 3062 of the same name. As a result of issuing this guidance, CICA section 3450, "Research and Development Costs," and Emerging Issues Committee Abstract No. 27, "Revenues and Expenditures during the Pre-Operating Period," was withdrawn. This new guidance requires recognizing all goodwill and intangible assets in accordance with CICA section 1000, "Financial Statement Concepts." Section 3064 eliminates the current practice of recognizing items as assets that do not meet the section 1000 definition and recognition criteria.

Business Combinations

In December 2008, the CICA issued section 1582 "Business Combinations," which will replace CICA section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. Currently only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation. Section 1582 will be effective for PET on January 1, 2011 with prospective application. PET did not early adopt this standard in 2009.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (“IFRS”)

Effective January 1, 2011 IFRS will replace GAAP in Canada for publicly accountable enterprises. PET’s first reporting period under IFRS will be interim financial statements for period ended March 31, 2011 and first IFRS annual financial statements for year ended December 31, 2011.

The Trust has identified key internal personnel with expertise to manage its transition to IFRS. During 2009, PET staff were involved in external IFRS training and development by means of attending conferences, participating in special interest seminars, and focusing on training sessions put on by various accounting service firms. During 2009 PET personnel have also initiated a detailed review of IFRS standards and other guidance in order to identify potential differences between current IFRS and current Canadian GAAP, as well as potential differences that may arise due to proposed changes in IFRS or Canadian GAAP prior to the 2011 transition date. As a result of proposed changes to certain IFRS standards, together with the current stage of the Trust’s IFRS project, PET cannot reasonably quantify the full impact that adopting IFRS will have on its financial position and future results. The Trust has identified potential differences between IFRS and Canadian GAAP, as described below.

Property, plant and equipment

PET currently groups similar assets for DD&A purposes under successful efforts accounting. Under IFRS, individual components of an item of property, plant and equipment may be separated and depreciated separately over their respective useful lives. PET, as a successful efforts reporter under Canadian GAAP, anticipates that IFRS transition adjustments on its oil and gas assets will not be as extensive had it been full cost oil and gas reporter.

Asset and goodwill impairment

Under Canadian GAAP, asset impairment is a two-stage test, where the carrying amount of the asset is first compared to the sum of the expected undiscounted future cash flows; if the first test indicates that an impairment exists, then the impairment loss recorded is measured as the difference between the carrying amount and the fair value. Under IFRS, assets are separated into cash-generating units (CGUs), and only the second fair value test is used both to guage the likelihood of and record the amount of the impairment. Generally, more impairment losses will result from applying IFRS standards as compared to Canadian GAAP. Impairment losses can also be reversed under IFRS, which is not permitted under Canadian GAAP.

Goodwill impairment is assessed under Canadian GAAP by comparing the carrying value of each reporting unit, including goodwill, to the fair value of the reporting unit. Under IFRS, goodwill acquired in a business combination is allocated to each CGU that is expected to benefit from the combination, and an impairment loss is recognized when the recoverable amount is less than the carrying amount, including goodwill.

Asset retirement obligation

Under Canadian GAAP, future asset retirement obligations are discounted to arrive at a net present value using a credit-adjusted risk-free interest rate. Under IFRS such obligations are also discounted, but the discount rate used is not credit-adjusted, leading to generally higher asset retirement obligations than under Canadian GAAP.

Further differences may be identified as PET continues its review of IFRS standards in 2010.

Prior to the implementation date, the Trust intends on completing a detailed financial statement level assessment of the impact of IFRS conversion. During this period, PET will decide on accounting policies permissible under IFRS, which fit the Trust’s operations and business strategy. PET intends to proceed with integration of the selected accounting policies for the opening balance sheet on January 1, 2010, which will be used for comparative purposes once the IFRS conversion is effective January 1, 2011. PET will actively monitor the effects of the IFRS conversion on information technology systems and internal controls over financial reporting.

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.

Changes in Tax Legislation

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

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

The Administrator intends that PET will continue to qualify as a mutual fund trust for purposes of the Income Tax Act (Canada) until such time as the Trust decides to convert to a corporation as may be encouraged by the changes to the Trust Tax Legislation announced on October 31, 2006. We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and our Unitholders. Some of the consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders including income generated by the royalties held by us. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders who are not residents of Canada and residents of Canada who are otherwise exempt from Canadian income tax;
- We would cease to be eligible for the capital gains refund mechanism available under Canadian tax legislation;
- Trust Units held by Unitholders who are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them; and
- Trust Units would not constitute qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs") or deferred profit sharing plans ("DPSPs"). If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to 1 percent of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units it may have its registration revoked by the Canada Revenue Agency.

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

Strategy Post-2010

The Trust anticipates converting to a corporation before January 1, 2011. The corporate conversion is expected to be achieved through a Plan of Arrangement which must be approved by the Administrator’s Board of Directors as well as the Trust’s unitholders through a meeting currently anticipated to be held in 2010. There is a risk that Unitholders may not approve the proposed conversion to a corporation, however the Canadian government has legislated the SIFT tax beginning in 2011 which effectively removes the benefits of remaining a trust. There is also a risk that conversion could create a taxable event for some unitholders.

Trust Units as Qualified investments under the Income Tax Act (Canada)

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

Trust Tax Legislation

The Trust Tax Legislation results in a tax applicable at the trust level on certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and treats distributions as dividends to the Unitholders. Existing trusts 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.

Shut in Natural Gas Reserves as a Result of Gas Over Bitumen Issues

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

On July 24, 2007 the ERCB's predecessor, the AEUB released Decision 2007-056 related to the application for shut-in of certain natural gas production in northeast Alberta. Although PET does not produce natural gas 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. It is possible that such a strategy, when drafted and implemented by the AEUB, 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.

On October 16, 2009 PET announced that the ERCB issued Decision 2009-061 in response to applications by Sunshine Oilsands Ltd. and Total E&P Canada Ltd. for the shutin of gas in the Liege Field within the Athabasca Oil Sands Area. Having considered the evidence submitted to an interim hearing, the ERCB concluded that production of gas from 228 intervals in 158 wells may present a risk to future bitumen recovery, pending the outcome of the full hearing of the applications. The Board also decided to shut in gas on an interim basis from 51 additional intervals in the Liege Wabiskaw A Pool, 15 additional intervals in the Liege Leduc A Pool, two additional intervals in the Liege Wabiskaw O Pool, and one additional interval in the Liege Wabiskaw M Pool.

Gas production of approximately 8.6 MMcf/d from a total of 70 wells was shut-in by the Trust effective October 31, 2009, pursuant to Decision 2009-061. An additional 18 wells with production of approximately 1.9 MMcf/d have also been shut-in due to the shut-in of facilities in the area.

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

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

Solution Gas Ownership

A portion of PET's natural gas production is from properties where third parties hold bitumen rights. Certain of these third parties have suggested that "solution gas" exists within the bitumen and that therefore this solution gas is the property of the bitumen rights holder. If this is proven to be correct, and if it is demonstrated that this solution gas has been or may continue to be produced in association with the recovery of PET's conventional natural gas rights, these facts may give rise to a third party claim for compensation. A successful claim in this regard may have a material adverse effect on the Trust's business, financial condition and operations.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Trust depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Trust may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Trust's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Trust will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Trust may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Trust.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Trust may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Trust. In accordance with industry practice, the Trust is not fully insured against all of these risks, nor are all such risks insurable. Although the Trust maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Trust could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused volatility to commodity prices. These conditions worsened in 2008 and continued in 2009 causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009, these factors have negatively impacted company valuations and may impact the performance of the global economy going forward.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Trust is and will continue to be affected by numerous factors beyond its control. The Trust's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Trust may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Trust's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Trust's reserves. The Trust might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Trust's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Trust. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Trust's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Trust may, in part, be determined by the Trust's borrowing base. A sustained material decline in prices from historical average prices could reduce the Trust's borrowing base, therefore reducing the bank credit available to the Trust which could require that a portion, or all, of the Trust's bank debt be repaid.

The Trust manages commodity price uncertainty through financial hedges and physical forward sale arrangements. There is a credit risk associated with counterparties with which the Trust may contract.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Trust makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Trust's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Trust. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Trust can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Trust, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Trust.

Operational Dependence

Other companies operate some of the assets in which the Trust has an interest. As a result, the Trust has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Trust's financial performance. The Trust's return on assets operated by others therefore depends upon a number of factors that may be outside of the Trust's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Trust manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Project cost over-runs could make a project uneconomic. The Trust's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Trust's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Trust could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. The Trust competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Trust also 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. The Trust's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Trust. The Trust's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Trust's costs, any of which may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Trust will require licenses from various governmental authorities. There can be no assurance that the Trust will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require additionalexpenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Trust to incur costs to remedy such discharge. Although the Trust believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases".

There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. The result of such meeting was the Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol. The Trust's exploration and production facilities and other operations and activities emit greenhouse gases and require the Trust to comply with Alberta's greenhouse gas emissions legislation contained in the Climate Change and Emissions Management Act and the Specified Gas Emitters Regulation. The Trust will also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which are now expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto

Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Trust. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Trust and its operations and financial condition.

The direct or indirect costs of these regulations may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Trust's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Trust's reserves as determined by independent evaluators.

To the extent that the Trust engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Trust may contract.

An increase in interest rates could result in a increase in the amount the Trust pays to service debt, which could negatively impact the market price of the Trust Units.

Substantial Capital Requirements

The Trust anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Trust's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future exploration and development programs and fund future acquisitions. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Trust to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Trust. The inability of the Trust to access sufficient capital for its operations could have a material adverse effect on the Trust's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Trust's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Trust may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Trust to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Trust's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Trust's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Trust's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Trust. Continued uncertainty in domestic and international credit markets could materially affect the Trust's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Trust's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Trust may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Trust's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Trust may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Trust's articles nor its by-laws limit the amount of indebtedness that the Trust may incur. The level of the Trust's indebtedness from time to time, could impair the Trust's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Trust and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Trust's claim which may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Trust's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Trust's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Trust's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Trust intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date, and has not been updated and thus does not reflect changes in the Trust's reserves since that date.

Insurance

The Trust's involvement in the exploration for and development of oil and natural gas properties may result in the Trust becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Trust maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Trust may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Trust. The occurrence of a significant event that the Trust is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Trust is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil and natural gas. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have an impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Trust's net production revenue.

In addition, the Trust's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Trust's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. The Trust will not have insurance to protect against the risk from terrorism.

Management of Growth

The Trust may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Trust to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Trust to deal with this growth may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

The Trust's properties are held in the form of licences and leases and working interests in licences and leases. If the Trust or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Trust's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

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.

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity which could impact the production and future revenues of the Trust. In addition high demand for equipment in winter months for areas limited to winter access could result in increased costs and the inability to execute the Trust's desired exploration and development programs.

Third Party Credit Risk

The Trust may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, commodity price and currency hedge contract counterparties, and other parties. In the event such entities fail to meet their contractual obligations to the Trust, such failures may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Trust's ongoing capital program, potentially delaying the program and the results of such program until the Trust finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Administrator are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

Reliance on Key Personnel

The Trust's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. The contributions of the existing management team to the immediate and near term operations of the Trust are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Trust will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Administrator.

Operations in Other Jurisdictions and Other Business Activities

Our operations and the expertise of our management are currently focused on conventional shallow and unconventional tight gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities 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, 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. In either case, our future operational and financial conditions could be materially adversely affected.

Lender Limitations on Distributions on Trust Units and Cash Redemptions of Trust Units

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

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

Disposition of Trust Units

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

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

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

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

Dilution

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

Statutory Rights Related to Trust Units

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

Personal Liability

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

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

Generally Accepted Accounting Principles ("GAAP")

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

Permitted Investments

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

Trust Structure

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

Changes in Distributions

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

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.

In accordance with applicable securities laws, the Trust's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

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, is largely dependent upon economic variables and the ability of the operator of the property. Operating costs on most properties have increased 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, 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 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 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 an 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 $360 million. The revolving nature of the credit facility is presently due to expire on May 24, 2010. 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. In addition the credit facility is subject to semi-annual borrowing base redeterminations. The lenders' assessments of the lending value attributable to PET's reserves may limit the amount available under the facility. 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.

Financial instruments

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;
- selling call options to third parties, giving them the right to purchase natural gas from the Trust at a specified price in future periods in exchange for an upfront cash payment to PET;
- 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 including unproved properties, 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.

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.

In addition, increasingly strict environmental requirements may 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 cash available for distribution to Unitholders and other uses.

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 available for distribution 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 gas price risk management 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 this program are reviewed against these criteria and the results actively monitored by the Board.

Beyond our price risk management 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 counterparty.

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

PET is also subject to interest rate risk to the extent its credit facility bears interest at a floating rate based on the lender's prime rate, and foreign exchange rate risk as a portion of the Trust's gas sales are on NYMEX and therefore denominated in US dollars. The Trust mitigates interest rate risk by having a portion of its overall debt in convertible debentures, which bear a fixed interest rate. PET may enter into financial forward foreign exchange contracts in order to limit exposure to US dollar sales from time to time, as the Trust considers appropriate.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to our future performance. All statements other than statements of historical fact may be forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "outlook", "strategy" and any similar expressions are intended to identify forward-looking information and statements.

In particular, but without limiting the foregoing, this annual information form contains forward-looking information and statements pertaining to the following: the quantity and recoverability of PET's reserves; the timing and amount of future production; future prices as well as supply and demand for natural gas and oil; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and hedging to be employed, and the value of financial forward natural gas contracts; funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; operating, G&A, and other expenses; cash distributions, and the funding and tax treatment thereof; amount of future abandonment and reclamation costs, asset retirement and environmental obligations; the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Trust's asset base; the Trust's acquisition strategy and the existence of acquisition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom; PET's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets; expected book value and related tax value of the Trust's assets and prospect inventory and estimates of net asset value; ability to fund distributions and exploration and development; our coporate strategy, including converting from an income trust to a corporation, the timing thereof and expenses related to the conversion, expectations regarding PET's access to capital to fund its acquisition, exploration and development activities; the transition to IFRS and its impact on the Trust's financial results; expected realization of gas over bitumen royalty adjustments; future income tax and its effect on funds flow and distributions; intentions with respect to preservation of tax pools of and taxes payable by the Trust; funding of and anticipated results from capital expenditure programs; renewal of and borrowing costs associated with the credit facility; future debt levels, financial capacity, liquidity and capital resources; future contractual commitments; drilling, completion, facilities and construction plans; the impact of Canadian federal and provincial governmental regulation on the Trust relative to other issuers; Crown royalty rates; PET's treatment under governmental regulatory regimes; business strategies and plans of management, including future changes in the structure of business operations and the planned conversion to a corporation in 2010; and the reliance on third parties in the industry to develop and expand PET's assets and operations.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Trust including, without limitation, that PET will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of PET to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of PET's reserve and resource volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the timing and costs of storage facility and pipeline construction and expansion and the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and funds flow to fund the Trust's capital and operating requirements as needed; and the extent of PET's liabilities.

PET believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: volatility in market prices for oil and natural gas products; supply and demand regarding PET's products; risks inherent in PET's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems; unanticipated operating events that can reduce production or cause production to be shut-in or delayed; changes in exploration or development plans by PET or by third party operators of PET's properties; reliance on industry partners; uncertainties or inaccuracies associated with estimating reserves volumes; competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance; increased costs; incorrect assessments of the value of acquisitions; increased debt levels or debt service requirements; industry conditions including fluctuations in the price of natural gas and related commodities; 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; the need to obtain required approvals from regulatory authorities; changes in laws applicable to the Trust, royalty rates, or other regulatory matters; general economic conditions in Canada, the United States and globally; stock market volatility and market valuations; limited, unfavourable, or a lack of access to capital markets, and certain other risks detailed from time to time in PET's public disclosure documents including, without limitation, those risks and contingencies described above and under ‘‘**Risk Factors**” in this MD&A. The foregoing list of risk factors should not be considered exhaustive.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Trust or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, unless expressly required to do so by applicable securities laws.

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.