2008 Q2

SECOND QUARTER SUMMARY

Maximize Cash Flow

- Production increased 22% to 188.4 MMcfe/d from 155.0 MMcfe/d in the second quarter of 2007, due primarily to the acquisition of natural gas assets in central Alberta in June 2007 ("Birchwavy Assets") as well as production additions in the Northern district core areas from a successful winter capital program. Production increased 3% from 183.8 MMcfe/d in the first quarter of 2008 as a result of the full effect of winter program production additions in the Northern district, partially offset by the disposition of several minor non-core assets in southern Alberta and Saskatchewan in the first quarter.
- Realized natural gas prices increased to $9.00 per Mcfe for the three months ended June 30, 2008 as compared to $8.80 per Mcfe for the comparative quarter in 2007, driven by a significant increase in AECO gas prices from quarter to quarter and despite realized hedging losses of $11.9 million for the current period. Realized gains on financial instruments for the three months ended June 30, 2007 totaled $19.6 million which significantly improved PET's realized natural gas price for the prior period.
- Revenue increased 24% to $154.3 million for the second quarter of 2008 from $124.1 million for the comparative period in 2007 due primarily to increased production volumes.
- Funds flow increased to $81.4 million ($0.73 per Trust Unit) for the three months ended June 30, 2008 from $72.7 million ($0.81 per Trust Unit) for the second quarter of 2007. Increased revenues were partially offset by higher royalties which increased substantially in 2008 as a percentage of revenue as royalties are calculated based on the Alberta Gas Reference Price. In the second quarter of 2007, PET's realized gas price significantly exceeded the Alberta Gas Reference Price; therefore, royalties as a percentage of revenue were approximately five percentage points lower in the second quarter of 2007 relative to 2008.
- For the period from July 1 to December 31, 2008, the weighted average price on financial hedges and physical forward sales contracts for an average of 101,000 GJ/d is $7.51 per GJ. Further price management is in place through March 2010.

Accretive Acquisitions

- In July 2008 PET closed non-core asset dispositions comprising approximately 0.5 MMcfe/d of production for proceeds of $9.9 million. To date in 2008, non-core asset dispositions total $16.9 million.

Asset Optimization

- Following a relatively long spring break-up period restricting access in the majority of PET's year-round access properties in the Southern district and East Side core areas, the Trust initiated its capital expenditure program for the remainder of 2008, drilling 7 gross (2.7 net) wells with a 100 percent success rate in the second quarter.
- PET's ongoing capital program continues to deliver good results with 6 gross (6.0 net) additional wells drilled and cased since the end of the second quarter. PET has budgeted capital spending of an additional net $51.5 million over the final two quarters of 2008. The Trust has two rigs scheduled to continue its 70 well second half 2008 drilling program. In addition, service rigs are operating to complete new wells and recomplete over 100 additional existing wells in new prospective zones.

Healthy Balance Sheet

- PET applied excess funds flows for the quarter to outstanding bank debt, resulting in a $35.5 million reduction in net bank debt from $346.3 million at March 31, 2008 to $310.8 million at June 30, 2008.
- The Dividend Reinvestment and Optional Cash Purchase Plan ("DRIP") contributed $4.4 million to PET's balance sheet in Q2. In March 2008 PET suspended the optional cash purchase component of its DRIP plan. The distribution reinvestment portion of the plan continues to be available to Unitholders at 94% of PET's market price.
- Strong gas prices and several non-core asset dispositions have increased the Trust's financial flexibility substantially. Projected exit 2008 net bank debt to 2008 projected funds flow is 1.0 times at the current forward market for natural gas prices.

Maximize Unitholder Value

- Distributions payable for the second quarter of 2008 totaled $0.30 per Trust Unit, comprised of $0.10 per Trust Unit paid on May 15, June 16 and July 15. Cumulative distributions to the end of the second quarter since inception in February 2003 totaled $12.524 per Trust Unit.
- PET's payout ratio for the second quarter of 2008 was 41% of funds flow.

CANADA'S PREMIUM NATURAL GAS TRUST

Paramount Energy Trust ("PET" or the "Trust") is a fully functional oil and gas business operating in a sustainable cash flow distributing trust structure. Since inception our primary goal has been to generate premium returns while growing a focused low risk, low exposure exploration and production business. Since operations as a trust commenced in February 2003, there has been substantial value creation: Cash distributions approximating 150% of our initial net asset value have been paid to Unitholders while sustaining production and reserves per Unit and growing the land base and inventory of opportunities. PET's team is accountable, entrepreneurial and motivated by excellence. We will continue to be focused on maximizing Unitholder value through the four pillars of our business plan while managing the Trust through volatile commodity price cycles, evolving market conditions and the government's proposed changes to the trust structure in Canada in 2011.

FINANCIAL AND OPERATING HIGHLIGHTS

($Cdn thousands except volume and per Trust Unit amounts)	Three Months Ended June 30 2008	2007	% Change	Six Months Ended June 30 2008	2007	% Change
Financial						
Revenue, including realized gains and losses on financial instruments	**154,332**	124,061	24	**276,210**	238,045	16
Funds flow [1]	**81,350**	72,669	12	**137,541**	138,266	(1)
Per Trust Unit [2]	**0.73**	0.81	(10)	**1.24**	1.58	(21)
Net earnings (loss)	**(55,365)**	9,218	(701)	**(141,025)**	(30,043)	369
Per Trust Unit [2]	**(0.50)**	0.10	(600)	**(1.27)**	(0.34)	274
Distributions	**33,343**	39,350	(15)	**66,452**	80,625	(18)
Per Trust Unit [3]	**0.30**	0.42	(29)	**0.60**	0.90	(33)
Payout ratio (%) [1]	**41.0**	54.1	(24)	**48.3**	58.3	(17)
Total assets	**1,148,245**	1,301,516	(12)	**1,148,245**	1,301,516	(12)
Net bank and other debt outstanding [4]	**310,818**	400,408	(22)	**310,818**	400,408	(22)
Convertible debentures, at principal amount	**236,034**	236,109	-	**236,034**	236,109	-
Total net debt [4]	**546,852**	636,517	(14)	**546,852**	636,517	(14)
Unitholders' equity	**139,253**	383,600	(64)	**139,253**	383,600	(64)
Capital expenditures						
Exploration and development	**16,339**	22,303	(27)	**62,783**	85,587	(27)
Acquisitions, net of dispositions	**(527)**	449,857	(100)	**(6,873)**	452,697	(102)
Other	**235**	219	7	**661**	590	12
Net capital expenditures	**16,047**	472,379	(97)	**56,571**	538,874	(90)
Trust Units outstanding (thousands)						
End of period	**111,350**	107,568	4	**111,350**	107,568	4
Weighted average	**111,055**	89,227	24	**110,612**	87,531	26
Incentive Rights outstanding	**7,144**	4,038	77	**7,144**	4,038	77
Trust Units outstanding at August 7, 2008	**111,517**					
Operating						
Production						
Total natural gas (Bcfe) [7]	**17.3**	14.1	23	**33.9**	26.9	26
Daily average natural gas (MMcfe/d) [7]	**188.4**	155.0	22	**186.1**	148.4	25
Gas over bitumen deemed production (MMcf/d) [5]	**19.6**	19.8	(1)	**19.8**	19.8	-
Average daily (actual and deemed - MMcfe/d) [5]	**208.0**	174.8	19	**205.9**	168.2	22
Per Trust Unit (cubic feet equivalent/d/Unit) [2]	**1.87**	1.96	(4)	**1.86**	1.92	(3)
Average natural gas prices ($/Mcfe)						
Before financial hedging and physical forward sales [6]	**9.82**	7.27	35	**8.45**	7.30	16
Including financial hedging and physical forward sales [6]	**9.00**	8.80	2	**8.15**	8.86	(8)
Land (thousands of net acres)						
Undeveloped land holdings	**1,996**	1,338	49	**1,996**	1,338	49
Drilling (wells drilled gross/net)						
Gas	**7/2.7**	5/5.0	40/(46)	**42/31.3**	82/65.4	(49)/(52)
Dry	**-/-**	-/-	-/-	**2/1.6**	7/6.2	(71)/(74)
Total	**7/2.7**	5/5.0	40/(46)	**44/32.9**	89/71.6	(51)/(54)
Success rate (%)	**100/100**	100/100	-/-	**95/95**	92/91	3/4

(1) These are Non-GAAP measures. Please refer to "Significant Accounting Policies and Non-GAAP Measures" included in management's discussion and analysis.

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

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

(4) Net debt includes net working capital (deficiency) before short-term financial instrument assets and liabilities. Total net debt includes convertible debentures measured at principal amount. Please refer to "Significant Accounting Policies and Non-GAAP Measures" included in management's discussion and analysis.

(5) The deemed production volume 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 volume is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution which is received monthly from the Alberta Crown as a reduction against other royalties payable.

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

(7) Production amounts are based on the Trust's interest before royalties.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of PET's operating and financial results for the three and six months ended June 30, 2008 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 consolidated financial statements and accompanying notes for the three and six months ended June 30, 2008 and 2007 as well as the Trust's audited consolidated financial statements and accompanying notes and MD&A for the years ended December 31, 2007 and 2006. Readers are referred to the advisories regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information" section of this MD&A. The date of this MD&A is August 7, 2008.

Mcf equivalent (Mcfe) may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), an Mcfe conversion ratio for oil of 1 bbl: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. For natural gas, gigajoules ("GJ") are converted to Mcf at a conversion ratio of 1.0546 GJ: 1 Mcf.

SIGNIFICANT ACCOUNTING POLICIES AND NON-GAAP MEASURES

Successful efforts accounting

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

Funds flow

Management uses funds flow from operations before certain exploration costs, expenditures on asset retirement obligations and changes in non-cash working capital ("funds flow"), funds flow per Trust Unit and annualized funds flow to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore it may not be comparable to the calculation of similar measures for other entities. Funds flow as presented is not intended to represent operating 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	Three months ended June 30		Six months ended June 30	
($ thousands except per Trust Unit amounts)	**2008**	2007	**2008**	2007
Cash flow provided by operating activities	**65,128**	65,999	**118,029**	132,948
Exploration costs (1)	**1,416**	2,188	**4,440**	6,412
Expenditures on asset retirement obligations	**1,190**	(166)	**2,906**	1,665
Changes in non-cash operating working capital	**13,616**	4,648	**12,166**	(2,759)
Funds flow	**81,350**	72,669	**137,541**	138,266
Funds flow per Trust Unit (2)	**$ 0.73**	$ 0.81	**$ 1.24**	$ 1.58

(1) Certain exploration costs are added back 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 back to funds flow include seismic expenditures, dry hole costs and expired leases 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.

OPERATIONS

Production

Natural gas production by core area (MMcfe/d)	Three months ended June 30		Six months ended June 30	
	2008	2007	**2008**	2007
Northern District				
West Side	**38.6**	44.3	**38.2**	42.4
East Side	**29.1**	28.6	**27.4**	26.3
Athabasca	**56.3**	60.0	**54.5**	60.0
Northern District total	**124.0**	132.9	**120.1**	128.7
Southern District				
Birchwavy West	**20.9**	3.0	**22.9**	3.0
Birchwavy East	**31.6**	6.3	**30.3**	5.1
East Central	**4.3**	2.8	**4.0**	2.3
Southern District total	**56.8**	12.1	**57.2**	10.4
Severo Energy Corp.	**6.3**	6.4	**7.0**	5.4
Other	**1.3**	3.6	**1.8**	3.9
Total	**188.4**	155.0	**186.1**	148.4
Deemed production from gas over bitumen financial solution	**19.6**	19.8	**19.8**	19.8
Total actual plus deemed production	**208.0**	174.8	**205.9**	168.2

Average production measured 188.4 MMcfe/d for the three months ended June 30, 2008, a 22 percent increase from 155.0 MMcfe/d reported in the second quarter of 2007. The significant increase in production is due primarily to the full effect of the acquisition of natural gas properties and related assets located in east central Alberta (the "Birchwavy Acquisition") which closed on June 26, 2007 as well as continuing development of the Trust's existing properties. PET's winter capital program added approximately 18 MMcfe/d (first 12 month average) of new production, which had the effect of limiting natural declines on the Trust's northeast Alberta assets to seven percent year over year. Including the deemed production volume related to the gas over bitumen financial solution, average aggregate daily production (actual and deemed) increased 19 percent to 208.0 MMcfe/d from 174.8 MMcfe/d in the second quarter of 2007. Production increased three percent from 183.8 MMcfe/d in the first quarter of 2008 as a result of the full effect of production additions in the Northern district, partially offset by the disposition of several minor non-core assets in southern Alberta and Saskatchewan in the first quarter.

Production for the six months ended June 30, 2008 increased 25 percent to 186.1 MMcfe/d from 148.4 MMcfe/d in the comparative period for 2007. Current production is approximately 185 MMcfe/d.

Capital expenditures

Capital expenditures ($ thousands)	Three months ended June 30		Six months ended June 30	
	2008	2007	**2008**	2007
Exploration and development expenditures (1)	**$ 13,300**	$ 19,682	**$ 59,121**	$ 80,791
Crown and freehold land purchases	**3,039**	2,621	**3,662**	4,796
Acquisitions	**83**	450,894	**119**	455,787
Dispositions	**(610)**	(1,037)	**(6,992)**	(3,090)
Other	**235**	219	**661**	590
Total capital expenditures	**$ 16,047**	$ 472,379	**$ 56,571**	$ 538,874

(1) Exploration and development expenditures for the three and six months ended June 30, 2008 include $1.4 million and $4.4 million, respectively in exploration costs (three and six months ended June 30, 2007 - $2.2 million and $6.4 million, respectively) which have been expensed directly on the Trust's statement of earnings (loss) in accordance with the successful efforts method of accounting. Exploration costs including seismic expenditures, dry hole costs and expired leases are considered by PET to be more closely related to investing activities than operating activities, and therefore they are included with capital expenditures in this table.

Exploration and development expenditures totaled $13.3 million for the three months ended June 30, 2008, and were concentrated on drilling, completion and facilities construction activities primarily in the Southern district. PET drilled 7 wells (2.7 net) with a 100 percent net success rate in the quarter, and conducted extensive recompletion activities in Birchwavy West, Birchwavy East and Saskatchewan. Exploration and development expenditures of $59.1 million for the six months ended June 30, 2008 were directed primarily towards drilling, completion and tie-in activities distributed throughout the Trust's three core areas in the Northern district.

PET acquired 94,000 net acres of Crown and freehold lands at an average price of $32 per acre in the second quarter of 2008. Of the net acreage acquired, 59,500 acres relate to the purchase of oil sands leases within the Athabasca core area.

In 2008, PET initiated a process to lease out to third parties certain undeveloped fee-simple lands obtained with the Birchwavy Acquisition in order to accelerate development of this acreage and generate lease bonus proceeds, cash flows from lease rental payments and royalties on production without any corresponding capital expenditures by the Trust. Bonus proceeds of $0.4 million received in the second quarter of 2008 were recorded as proceeds from dispositions. The three year paid up lease rental payments of $0.2 million received in the second quarter of 2008 are recorded as a reduction to exploration expenses.

In July of 2008 PET closed the disposition of certain royalty and non-core working interests representing 0.5 MMcfe/d of production for proceeds of $9.9 million. Non-core dispositions total $16.9 million to date in 2008.

MARKETING

Natural gas prices

	Three months ended June 30		Six months ended June 30	
Natural gas prices ($/Mcfe, except percent amounts)	**2008**	2007	**2008**	2007
Reference prices				
AECO Monthly Index	**9.35**	7.37	**8.24**	7.41
AECO Daily Index	**10.20**	7.07	**9.09**	7.24
Alberta Gas Reference Price (1)	**9.37**	6.88	**8.28**	6.96
Average PET prices				
Before financial hedging and physical forward sales (2)	**9.82**	7.27	**8.45**	7.30
Percent of AECO Monthly Index (%)	**105**	99	**103**	99
Before financial hedging (3)	**9.69**	7.41	**8.42**	7.60
Percent of AECO Monthly Index (%)	**104**	101	**102**	103
After financial hedging and physical forward sales	**9.00**	8.80	**8.15**	8.86
Percent of AECO Monthly Index (%)	**96**	119	**99**	120

(1) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties. Alberta Gas Reference Price for June 2008 is an estimate.

(2) PET's commodity hedging strategy employs both financial forward contracts and physical natural gas delivery contracts at fixed prices or price collars. In calculating the Trust's natural gas price before financial hedging and physical forward sales, 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.

Realized natural gas prices increased two percent for the three months ended June 30, 2008 to $9.00 per Mcfe from $8.80 per Mcfe in 2007, as compared to a 27 percent increase in AECO Monthly Index prices from quarter to quarter. The significant increase in hub pricing was fueled by lower year over year gas storage inventories from winter heating demand and a dramatic rise in the price of crude oil. The Trust's realized gas price was 96 percent of the AECO Monthly Index price primarily as a result of realized losses of $11.9 million on financial forward natural gas contracts. In the three months ended June 30, 2007, PET realized $18.6 million in financial instrument gains related to early termination of fixed-price forward financial contracts, which increased the Trust's realized gas price by 18 percent in that quarter.

Realized natural gas prices for the six months ended June 30, 2008 measured $8.15 per Mcfe as compared to $8.86 per Mcfe in the first half of 2007. In the first half of 2008 PET has realized losses of $9.1 million on its financial hedges and physical forward sales contracts relative to AECO Monthly Index pricing against which these contracts settle. In 2007, higher realized prices were a result of $33.9 million in gains on financial forward natural gas contracts.

PET has determined its exposure to CEG Energy Options Inc. ("CEG"), a Canadian subsidiary of oil and natural gas marketer SemGroup, L.P. ("SemGroup") to be approximately $0.2 million, related to natural gas sales for June and July 2008. In July 2008 SemGroup filed a voluntary position for reorganization under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court. Natural gas deliveries to CEG have been terminated and as such there is no additional potential financial exposure for the Trust.

Risk management

PET's risk management strategy is focused on using financial instruments to mitigate the effect of commodity price volatility on funds flow and distributions, to lock in attractive economics on acquisitions and to take advantage of perceived anomalies in natural gas markets. The Trust maintains a balanced gas price risk management portfolio using both financial hedge arrangements and physical forward sales to hedge up to a maximum of 50 percent of forecast production including gas over bitumen deemed volumes. PET will also enter into foreign exchange swaps and physical or financial swaps related to the differential between natural gas prices at the AECO and NYMEX trading hubs in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Trust's realized gas price. The term "financial instruments" includes all financial and physical risk management contracts. Although PET considers 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 Paramount Energy Operating Corp.'s (the "Administrator") Board of Directors. PET's hedging strategy though designed to protect cash flow and distributions is opportunistic in nature. The Trust may elect to reduce or increase its hedging contracts depending on perceived position in the commodity price cycle. The Trust mitigates credit risk by entering into risk management contracts with financially sound, credit-worthy counterparties.

PET's hedging strategy has been focused on locking in periodic strength in AECO and NYMEX forward prices over the past two years to ensure a base level of production revenue, despite weakness in spot prices related to such factors as high gas storage levels, increases in liquefied natural gas ("LNG") imports into North America and variable cooling and heating demand. PET estimates that additional realized natural gas revenues and funds flows of $51.0 million in 2006 and $62.5 million in 2007 can be attributed to the Trust's risk management program.

The first half of 2008 saw a significant shift in several fundamental price drivers within natural gas markets. The arrival of extremely cold winter weather in major consuming regions had the effect of increasing natural gas usage and reducing storage levels. LNG imports also decreased dramatically as strong demand in Europe and Asia diverted LNG shipments to other global markets outside North America, further reducing storage levels such that natural gas storage in North America exited the second quarter of 2008 below the five-year average. These factors contributed to a 76 percent increase in AECO spot gas prices from $6.32 per GJ on December 31, 2007 to $11.10 per GJ on June 30, 2008 and a corresponding increase in AECO forward prices for the remainder of 2008.

As a result of the significant increase in forward natural gas prices during 2008, a net mark-to-market financial instrument liability of $129.6 million was recorded at June 30, 2008, and unrealized losses on financial instruments of $70.4 million and $149.6 million respectively were recorded for the three and six months then ended. The liability and unrealized loss are measured using forward prices in effect at the balance sheet date; had the Trust's financial instrument portfolio been marked to market as at August 6, 2008 the corresponding liability would have been approximately $10 million due to the decrease in natural gas prices since June 30, 2008. PET's funds flow and its ability to pay distributions is not impacted by these unrealized mark-to-market amounts.

A complete list of PET's outstanding financial instruments as at June 30, 2008 is disclosed in note 12 to the interim unaudited consolidated financial statements as at and for the three months ended June 30, 2008.

PET has continued to supplement its risk management program after the end of the second quarter. Financial and physical natural gas forward sales positions (net of related financial and physical fixed-price natural gas purchase contracts) at August 6, 2008 are as follows:

Financial and physical forward net sales positions

Type of Contract	Volumes at AECO (GJ/d) (2)	Price ($/GJ) (1)	AECO/NYMEX Futures Market Price ($/GJ) (3)	Term
Financial	82,000	7.55		September – October 2008
Physical	10,500	6.82		September – October 2008
Period Total	**92,500**	**7.47**	**7.35**	**September – October 2008**
Financial – NYMEX	10,000	US $7.70		September – October 2008
Period Total	**10,000**	**US $7.70**	**US $8.86**	**September – October 2008**
Financial	96,000	7.77		November 2008 – March 2009
Physical	2,500	8.37		November 2008 – March 2009
Period Total	**98,500**	**7.79**	**8.33**	**November 2008 – March 2009**
Physical	5,000	11.11		January 2009
Period Total	**5,000**	**11.11**	**8.52**	**January 2009**
Financial	65,000	8.70		April – October 2009
Period Total	**65,000**	**8.70**	**8.15**	**April – October 2009**
Financial	37,500	9.59		November 2009 – March 2010
Period Total	**37,500**	**9.59**	**8.97**	**November 2009 – March 2010**

(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. Included in the November 2008 – March 2009 volume summary is a collar to sell forward 5,000 GJ/d at a floor price of $7.00 per GJ at AECO and a ceiling price of $8.00 per GJ. The ceiling price is used in the weighted average price calculation.

(2) All transactions are at AECO unless identified specifically as a NYMEX transaction. NYMEX transactions are measured in US$ per MMBTU.

(3) Futures market reflects AECO/NYMEX forward market prices as at August 6, 2008. NYMEX forward prices are measured in US$ per MMBTU.

The Trust will also enter into financial and forward physical gas sales arrangements to fix the basis differential between the NYMEX and AECO trading hubs. The price at which these contracts settle is equal to the NYMEX index less a fixed basis amount. As of June 30, 2008 and August 6, 2008 the Trust has entered into arrangements to offset its forward basis sales positions and therefore has no net open basis positions. A complete list of PET's basis transactions as at June 30, 2008 is disclosed in note 12 to the interim unaudited consolidated financial statements.

FINANCIAL RESULTS

Revenue

Revenue ($ thousands)	Three months ended June 30 2008	2007	Six months ended June 30 2008	2007
Natural gas revenue, before financial hedging (1)	**166,199**	104,451	**285,270**	204,144
Realized gains (losses) on financial instruments (2)	**(11,867)**	19,610	**(9,060)**	33,901
Total revenue	**154,332**	124,061	**276,210**	238,045

(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 and options.

Oil and natural gas revenues increased to $154.3 million for the three months ended June 30, 2008 compared to $124.1 million for the second quarter of 2007 primarily due to a 22 percent increase in natural gas production levels. Oil and natural gas revenue increased 16 percent to $276.2 million for the six months ended June 30, 2008 from $238.0 million for the first six months of 2007 as higher production levels were partially offset by an eight percent decrease in realized natural gas prices.

Funds flow

	Three months ended June 30				Six months ended June 30			
	2008		2007		2008		2007	
Funds flow reconciliation	**$ millions**	**$/Mcfe**	$ millions	$/Mcfe	**$ millions**	**$/Mcfe**	$ millions	$/Mcfe
Production (Bcfe)		**17.1**		14.1		**33.9**		26.9
Revenue (1)	**154.4**	**9.00**	124.1	8.80	**276.2**	**8.15**	238.1	8.86
Royalties	**(29.3)**	**(1.71)**	(18.4)	(1.31)	**(47.0)**	**(1.39)**	(33.1)	(1.23)
Operating costs	**(28.6)**	**(1.67)**	(21.7)	(1.54)	**(61.6)**	**(1.82)**	(47.1)	(1.75)
Transportation	**(3.7)**	**(0.22)**	(3.0)	(0.21)	**(7.3)**	**(0.22)**	(5.7)	(0.21)
Operating netback (3)	**92.8**	**5.40**	81.0	5.74	**160.3**	**4.72**	152.2	5.67
Gas over bitumen royalty adjustments	**6.2**	**0.36**	4.8	0.34	**10.4**	**0.31**	9.8	0.36
Lease rentals	**(0.6)**	**(0.03)**	(0.6)	(0.04)	**(1.2)**	**(0.04)**	(1.5)	(0.05)
General and administrative (2)	**(9.3)**	**(0.54)**	(5.4)	(0.38)	**(16.3)**	**(0.48)**	(9.4)	(0.35)
Interest on bank and other debt	**(3.9)**	**(0.23)**	(4.4)	(0.31)	**(8.1)**	**(0.24)**	(7.5)	(0.28)
Interest on convertible debentures (2)	**(3.8)**	**(0.22)**	(2.7)	(0.19)	**(7.6)**	**(0.22)**	(5.3)	(0.19)
Funds flow (2) (3)	**81.4**	**4.74**	72.7	5.16	**137.5**	**4.05**	138.3	5.16

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

(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

For the three and six months ended June 30, 2008, PET's average royalty rate (royalties as a percentage of revenues including gains and losses on financial instruments) climbed to 19.0 percent and 17.0 percent, respectively from 14.8 percent and 13.9 percent, respectively for the three and six months ended June 30, 2007. Alberta Crown royalties are based on the Alberta Gas Reference Price. The higher royalty rates in 2008 are due to PET's realized natural gas price being closer to the average Alberta Gas Reference Price (98 percent of the Alberta Gas Reference Price in the first half of 2008 as opposed to 127 percent of the Alberta Gas Reference Price in 2007). Royalty expense increased from $18.4 million for the three months ended June 30, 2007 to $29.3 million for the current quarter as a result of higher natural gas production volumes and a significant increase in the Alberta Gas Reference Price.

New Alberta Royalty Regime

On October 25, 2007, the Government of Alberta announced a "New Royalty Framework" for oil and natural gas royalties in the Province of Alberta. New royalty rates will apply to all production effective January 1, 2009. While detailed Regulations have yet to be released, PET's initial assessment is that, based on the Trust's profile of well productivity for the first quarter of 2008 and at various natural gas prices, the effect of the new royalty framework on PET's royalty rate including estimated deductions for capital cost allowance and custom processing would be approximately as shown below. Crown royalty rates would rise relative to their current levels at higher gas prices and decrease relative to their current levels at lower gas prices. The rates presented are for Crown royalties only and do not include freehold and overriding royalties paid to landowners.

Estimated change in royalty rate	AECO Gas Price ($/GJ) $6.00	$7.00	$8.00	$10.00
Crown royalty rate under current royalties	11.2%	11.9%	12.4%	13.1%
Estimated Crown royalty rate under new royalty framework	5.6%	9.3%	12.0%	17.6%
Increase (decrease) in royalty rate (percentage points)	(5.6)	(2.6)	(0.4)	4.5
Percentage increase (decrease) in royalty rate (%)	(50.0%)	(21.8%)	(3.0%)	34.4%

PET estimates that its total royalty rate for the three months ended June 30, 2008 including Crown, freehold and overriding royalties as a percentage of oil and natural gas revenues (including realized gains and losses on financial instruments) would have been 22.7 percent under the New Royalty Framework, as opposed to the 19.0 percent actually incurred for the current quarter under the current royalty structure. The Crown royalty rate for the current quarter would have been approximately 19.1 percent under the New Royalty Framework compared to 15.4 percent under the current structure. In this comparison of royalties under the current and new Alberta royalty framework, the impact of PET's realized gas price of $9.00 per Mcfe being lower than the Alberta Gas Reference price of $9.37 per Mcfe is that the Trust's Crown royalty rate is further inflated relative to that estimated in the above table which assumes Alberta Gas Reference pricing is realized.

Operating costs

Unit-of-production costs increased eight percent to $1.67 per Mcfe in the second quarter of 2008 as compared to $1.54 per Mcfe in the second quarter of 2007, and increased to $1.82 per Mcfe for the six months ended June 30, 2008 from $1.75 per Mcfe for the first six months of 2007. The higher unit-of-production costs in 2008 were primarily a result of $5.3 million in natural gas processing adjustments related to prior years that were recorded in the current six month period, $4.3 million of which were recorded in the second quarter. Excluding the processing adjustments, unit operating costs dropped eight percent to $1.42 per Mcfe for the three months ended June 30, 2008 and by five percent to $1.66 per Mcfe for the first half of 2008, as a result of having a higher proportion of the Trust's production in the Southern district, where operating costs tend to be incurred more uniformly throughout the year. Much of the Trust's northeast Alberta properties are only accessible for maintenance and workover activities in the winter months and therefore tend to incur higher operating costs in the first six months of the year. PET currently estimates operating costs to average $1.75 per Mcfe for the full year of 2008. Total operating costs increased to $28.6 million in the three months ended June 30, 2008 from $21.7 million for the same period in 2007 due to increased production volumes in the current quarter.

Transportation costs

Transportation costs increased $0.7 million to $3.7 million for the current quarter as compared to the second quarter of 2007 as a result of higher production volumes in the current period. Transportation costs on a unit-of-production basis increased marginally to $0.22 per Mcfe for the three and six month periods ended June 30, 2008 as compared to $0.21 per Mcfe for the three and six months ended June 30, 2007.

Operating netback

The 22 percent increase in natural gas production volumes was the primary driver in increasing the Trust's operating netback to $92.8 million for the three months ended June 30, 2008 from $81.0 million for the three months ended June 30, 2007, partially offset by a significant increase in PET's royalty rate. In the second quarter of 2007, PET's realized gas price significantly exceeded the Alberta gas reference price; therefore, royalties as a percentage of revenue were five percentage points lower in the second quarter of 2007 relative to 2008.

Operating netback reconciliation ($ millions)	
Production increase	26.8
Price increase, including realized gains on financial instruments	3.4
Royalty increase	(10.9)
Transportation cost increase	(0.7)
Operating cost increase	(6.8)
Increase in net operating income	11.8

General and administrative costs

General and administrative expenses increased $4.3 million to $11.3 million for the three months ended June 30, 2008 compared to $7.0 million for the three months ended June 30, 2007. The increase is due primarily to higher staff levels related to the Birchwavy Acquisition and the resulting expansion of PET's production base and number of core operational areas, as well as the ongoing focus on new venture opportunities in the Trust's portfolio. In addition PET moved its head office to leased space in December 2007 following the sale of its previous premises and as a result the Trust now incurs office lease expense, which totaled $0.7 million for the current quarter. Approximately $2.0 million in general and administrative expenses for the current period is in respect of non-cash stock-based compensation expense. General and administrative expenses for the six months ended June 30, 2008 totaled $19.3 million, an increase of $7.6 million over the comparative period for 2007, as a result of $1.4 million in office lease expense in the current period, a $0.6 million increase in stock-based compensation expense and higher staff levels related to the Trust's expanded asset base. General and administrative expenses are typically highest in the first and second quarters of each year due to annual compensation programs and activities related to the Trust's year end including audit and reserve evaluation fees and year end reporting to Unitholders.

Interest

Interest and other expense totaled $3.7 million for the three months ended June 30, 2008 as compared to $5.6 million for the comparable period in 2007. Interest expense in 2007 was affected by a $1.2 million loss related to the decrease in market value of the Trust's investment in Cordero Energy Inc. ("Cordero"), a publicly traded oil and gas exploration company, as well as higher interest rates on bank debt in 2007 as compared to 2008. The market

value of the investment in Cordero has risen by approximately $0.5 million in 2008, contributing to the lower interest expense in the current period. In July 2008 Cordero announced that all of its outstanding shares would be acquired for a combination of cash and stock by another publicly traded oil and gas company. The acquisition is expected to close in September 2008.

Interest on convertible debentures for the three months ended June 30, 2008 increased by $1.3 million compared to the three months ended June 30, 2007 due primarily to the issuance of $75 million of 6.5 percent convertible unsecured subordinated debentures in June 2007 as partial funding for the Birchwavy Acquisition. Included in convertible debenture interest expense is $0.8 million of non-cash expenses related primarily to the amortization of debt issue costs as compared to $0.6 million for the comparative period in 2007.

Gas over bitumen royalty adjustments

In 2004 and 2005 the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas ("Royalty Regulation"), which provide a mechanism whereby the Government may prescribe additional royalty components to effect a reduction in the royalty calculated through the Crown royalty system for operators of gas wells which have been denied the right to produce by the AEUB as a result of certain bitumen conservation decisions. The formula for calculation of the royalty reduction provided in the Royalty Regulation is:

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

The Trust's net deemed production volume for purposes of the royalty adjustment was 19.6 MMcf/d in the second quarter of 2008. Deemed production represents all PET natural gas production shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the AEUB, or through correspondence in relation to an AEUB ID 99-1 application. In accordance with IL 2004-36, the deemed production volume related to wells shut-in is reduced by ten percent per year on the anniversary date of the shut-in order. Deemed production decreased 0.2 MMcf/d from 19.8 MMcf/d for the three months ended June 30, 2007 as a result of the annual ten percent reduction in deemed production volumes discussed previously, partially offset by the acquisition of approximately 2.0 MMcf/d of deemed production in 2007.

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

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

For the three months ended June 30, 2008 the Trust received $6.2 million in gas over bitumen royalty adjustments, of which $1.1 million was classified as revenue and $5.1 million was recorded on the Trust's balance sheet, as compared to $4.8 million received in the second quarter of 2007. The increase in the current quarter was due to the higher Alberta Gas Reference Price as compared to 2007. Cumulative royalty adjustments received to June 30, 2008 total $88.0 million.

Funds flow

As a result of the variables discussed above, funds flow netbacks decreased seven percent from $5.16 per Mcfe in the second quarter of 2007 to $4.74 per Mcfe in the second quarter of 2008. Higher royalty and general and administrative expenses per Mcfe accounted for the reduction, partially offset by lower interest costs and a $0.20 per Mcfe increase in the Trust's realized gas price. Funds flow increased by 12 percent to $81.4 million ($0.73 per Trust Unit) for the three months ended June 30, 2008 from $72.7 million ($0.81 per Trust Unit) in the 2007 period due to higher production volumes in the current quarter. The decrease in funds flow per Trust Unit from 2007 was primarily due to the increased number of Trust Units outstanding as a result of financing activities for the Birchwavy Acquisition.

Depletion, depreciation, accretion and exploration expense

In accordance with successful efforts accounting, PET expenses exploration costs including seismic expenditures, dryhole costs and expired leases. Exploration expenses decreased to $2.0 million and $5.7 million, respectively for the three and six months ended June 30, 2008 from $2.7 million and $7.9 million, respectively for the second quarter and first six months of 2007 primarily due primarily to lower seismic expenditures during the 2008 period. Lease rental payments of $0.2 million received in the second quarter of 2008 for the lease of certain of PET's fee-simple lands were recorded as a reduction to exploration expenses.

Depletion, depreciation and accretion ("DD&A") expense increased from $50.8 million in the second quarter of 2007 to $57.2 million in 2008 due to increased production volumes. PET's depletion rate decreased seven percent to $3.34 per Mcfe in the three months ended June 30, 2008 as compared to $3.60 per Mcfe in the second quarter of 2007. The decrease in the DD&A rate for the second quarter of 2008 as compared to the DD&A rate in 2007 is due to the lower cost of proved reserve additions provided by the Birchwavy Acquisition.

Earnings (Loss)

The Trust reported a net loss of $55.4 million ($0.50 per basic and diluted Trust Unit) for the three months ended June 30, 2008 as compared to net earnings of $9.2 million ($0.10 per basic and diluted Trust Unit) for the 2007 period. The net loss in 2008 is due to a $70.4 million unrealized loss on financial instruments driven by the significant increase in AECO natural gas prices during the period. The Trust incurred a net loss of $141.0 million ($1.27 per basic and diluted Trust Unit) for the six months ended June 30, 2008 as compared to net loss of $30.0 million ($0.34 per basic Trust Unit) in 2007 as a result of an unrealized loss on financial instruments of $149.6 million in the first half of 2008. Based on spot and forward natural gas prices as at August 6, 2008, the year to date unrealized loss on financial instruments for instruments in place as at June 30, 2008 would have been approximately $120 million lower than the actual unrealized loss recorded at June 30.

Asset Retirement Obligation

The Trust's asset retirement obligation is estimated by a third party consulting firm based on PET's net ownership interest in all wells and facilities and estimated costs to abandon wells, decommission facilities and reclaim leases and roads, discounted at a credit-adjusted interest rate to arrive at a net present value figure. The timing of asset retirement expenditures is estimated based on the reserve life of assets according to the Trust's external reserve

report prepared as of December 31, 2007. These expenditures are currently expected to occur over the next 25 years with the majority of costs incurred between 2015 and 2020. PET's asset retirement obligation increased from $194.1 million at December 31, 2007 to $196.0 million at June 30, 2008 as accretion expense and additional obligations from 2008 drilling activity were partially offset by obligations disposed of in conjunction with non-core property dispositions and asset retirement expenditures of $2.9 million for the first six months of 2008.

Income taxes and proposed changes to trust tax legislation

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

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

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

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

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

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

The Trust's market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding publicly-traded Trust Units, was approximately $1.4 billion, which means the Trust's safe harbour equity growth amount for the period ending December 31, 2007 was approximately $560 million, and for each of calendar 2008, 2009 and 2010 is an additional approximately $280 million, not including equity issued to replace the Trust's debt that was outstanding on October 31, 2006, including convertible debentures. Failure to comply with the "normal growth" provisions as outlined would result in the Trust being subject to the new tax immediately, as opposed to January 1, 2011. Since October 31, 2006 PET has issued approximately $377 million of new Trust Units and convertible debentures through the public offering completed on June 20, 2007, the Trust's Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan") and Unit Incentive Plan.

In June 2008 the federal government proposed amendments to the trust tax regulation ("Provincial SIFT Tax Amendments") so that, instead of basing the provincial component of the tax on a flat tax rate of 13 percent, the provincial component would be instead based on the general provincial corporate income tax rate in each province in which PET has a permanent establishment. On July 14, 2008 the Department of Finance released draft legislation which proscribed the provincial allocation formula to be applied with respect to the Provincial SIFT tax. Specifically, PET's taxable distributions will be allocated to provinces by taking half of the aggregate of:

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

Under the Provincial SIFT Tax Amendments PET is considered to have 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. These regulations are not yet considered substantively enacted for accounting purposes at June 30, 2008 therefore the provincial component of the Trust Tax Legislation is 13 percent for financial statement purposes.

PET has not recorded a future income tax liability as a result of the Trust Tax Legislation being enacted. Based on production forecasts for PET's proved reserves included in the independent reserve report as at December 31, 2007, the tax values of the Trust's assets are projected to exceed the related book values by January 1, 2011, the date the direct tax on distributions within the Trust becomes effective. PET has estimated tax pools of $690 million at June 30, 2008 and intends to maximize the preservation of tax pools over the transition period in order to minimize the tax consequences faced by the Trust in 2011 and future years.

The draft legislation released by the Department of Finance also 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.

Among other things, the proposed amendments provide for:

- the tax-deferred exchange of SIFT trust units by a Unitholder to a taxable Canadian corporation for shares of the corporation without any administrative requirement to file election forms (Unit-for-Share Exchange);
- the tax-deferred distribution of properties of a SIFT trust to a taxable Canadian corporation (Wind-up Distribution);
- the flow-through of unused tax attributes of a SIFT trust to a taxable Canadian corporation as a consequence of a Wind-up Distribution; and
- the tax-deferred distribution of shares of a taxable Canadian corporation from a SIFT trust to the public (Share Distribution);

A variety of tax and other factors need to be weighed in determining if and when PET should convert to a corporation. Now that detailed rules are available on the mechanics for conversion, the Trust is in a better position to evaluate its options and determine the optimal course of action for PET's assets and business strategy going forward. PET is currently analyzing potential structures and courses of action however the Trust has not yet made a determination with respect to future changes in the structure of its business operations, if any.

SUMMARY OF QUARTERLY RESULTS

				Three months ended
($ thousands except where noted)	**June 30, 2008**	Mar 31, 2008	Dec 31, 2007	Sept 30, 2007
Natural gas revenues before royalties [1]	**166,199**	121,878	109,919	98,508
Natural gas production (MMcfe/d)	**188.4**	183.8	190.3	193.1
Funds flow [2]	**81,350**	56,191	59,622	41,212
Per Trust Unit - basic	**0.73**	0.51	0.55	0.38
Net earnings (loss)	**(55,365)**	(85,660)	(4,970)	5,246
Per Trust Unit - basic	**(0.50)**	(0.78)	(0.05)	0.05
- diluted	**(0.50)**	(0.78)	(0.05)	0.05
Realized natural gas price ($/Mcfe)	**9.00**	7.29	7.07	5.66
Average AECO Monthly Index price ($/Mcf)	**9.35**	7.13	6.00	5.64

				Three months ended
($ thousands except where noted)	June 30, 2007	Mar 31, 2007	Dec 31, 2006	Sept 30, 2006
	(restated)			
Natural gas revenues before royalties [1]	104,451	99,693	94,564	96,576
Natural gas production (MMcfe/d)	155.0	141.7	144.6	154.6
Funds flow [2]	72,669	65,597	58,166	60,770
Per Trust Unit - basic	0.81	0.76	0.69	0.72
Net earnings (loss)	9,218	(39,261)	(68,254)	19,619
Per Trust Unit - basic	0.10	(0.46)	(0.80)	0.23
- diluted	0.10	(0.46)	(0.80)	0.23
Realized natural gas price ($/Mcfe)	8.80	8.94	7.83	7.36
Average AECO Monthly Index price ($/Mcf)	7.37	7.46	6.36	6.03

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

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

Natural gas revenues were highest in the first and second quarters of 2008 primarily due to higher production levels as a result of the Birchwavy Acquisition. Funds flows are dependent on cash netbacks for gas production; as such they were highest in the second quarter of 2008 and the first and second quarters of 2007 when the realized gas price was highest and lowest in the third quarter of 2007 when the Trust's realized gas price dropped to $5.66 per Mcfe.

Net earnings were highest in the third quarter of 2006 as a result of unrealized gains on financial instruments. The net loss in the fourth quarter of 2006 was due to impairment charges at east central Alberta and Saskatchewan and higher DD&A expenses as compared to previous quarters. The net losses in the first quarter of 2007 and 2008 and the most recent quarter were due to unrealized losses of $48.5 million, $79.2 million and $70.4 million respectively on the change in mark-to-market value of PET's financial instruments during those periods.

LIQUIDITY AND CAPITAL RESOURCES

Net debt ($ thousands except per Trust Unit and percent amounts)	June 30, 2008	Three months ended December 31, 2007
Bank debt	**321,757**	342,190
Convertible debentures, measured at principal amount	**236,034**	236,109
Working capital deficiency (surplus) (1)	**(10,939)**	(6,519)
Net debt	**546,852**	571,780
Trust Units outstanding (thousands)	**111,350**	109,557
Market price at end of period ($/Trust Unit)	**10.04**	6.30
Market value of Trust Units	**1,117,954**	690,209
Total capitalization (1)	**1,664,806**	1,261,909
Net debt as a percentage of total capitalization (%)	**32.8**	45.3
Annualized funds flow (1)	**325,400**	238,488
Net debt to annualized funds flow ratio (times) (1)	**1.7**	2.4

(1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in this MD&A. Annualized funds flow in the prior year column is for the fourth quarter of 2007.

PET has a revolving credit facility with a syndicate of Canadian chartered banks. The revolving feature of the facility expires on May 25, 2009 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. The borrowing base on the facility is currently $400 million. Collateral for the credit facility is provided by a floating-charge debenture covering all existing and acquired property of the Trust excluding the assets of Severo Energy Corp ("Severo"), a 93 percent-owned subsidiary of the Trust, as well as unconditional full liability guarantees from all subsidiaries in respect of amounts borrowed under the facility. In addition Severo has a $10 million credit facility with a Canadian chartered bank. Bank debt decreased to $321.8 million at June 30, 2008, as compared to $342.2 million at December 31, 2007 as a result of funds flows in excess of distributions and capital expenditures during the period and proceeds of $12.7 million received through the Trust's distribution reinvestment program. In addition to amounts outstanding under the credit facility PET has outstanding letters of credit in the amount of $4.4 million.

At June 30, 2008 PET had convertible debentures outstanding as follows:

Convertible debentures	6.50%	2006 – 6.25%	2005 – 6.25%	8%
Principal outstanding ($ millions)	74.9	100.0	55.3	5.9
Maturity date	June 30, 2012	April 30, 2011	June 30, 2010	September 30, 2009
Conversion price ($ per Trust Unit)	14.20	23.80	19.35	14.20
Fair market value ($ millions)	72.7	99.4	55.3	6.0

Fair values of debentures are calculated by multiplying the number of debentures outstanding at June 30, 2008 by the quoted market price per debenture at that date. During the six month period ended June 30, 2008, $0.1 million of 6.5% Convertible Debentures were converted, resulting in the issuance of 5,281 Trust Units.

Net debt to annualized funds flow decreased to 1.7 times for the quarter ended June 30, 2008 from 2.4 times for the three months ended December 31, 2007 as a result of strong funds flows and the repayment of $20.4 million in bank debt during the period. Net debt to annualized funds flow in future quarters will primarily be dependent on the timing of capital expenditures and natural gas prices, which have experienced significant volatility in 2008.

A reconciliation of the decrease in net debt from December 31, 2007 to June 30, 2008 is as follows:

Reconciliation of net debt ($ millions)	
Net debt, December 31, 2007	571.8
Exploration and development and other capital expenditures	63.4
Dispositions, net of acquisitions	(6.9)
Funds flow	(137.5)
Distributions	66.5
Proceeds from DRIP plan	(12.7)
Increase in value of marketable securities	(0.6)
Expenditures on asset retirement obligations	2.9
Net debt, June 30, 2008	546.9

PET has a distribution reinvestment and optional Unit purchase plan ("DRIP plan") which provides Unitholders with the opportunity to reinvest monthly cash distributions to acquire additional Trust Units at 94 percent of the Treasury Purchase Price, which is defined as the daily volume weighted average trading price of the Trust Units for the ten trading days immediately proceeding a distribution payment date ("Treasury Purchase Price"). No additional commissions, service or brokerage fees are charged to the Unitholder for these transactions. Through the DRIP Plan $12.7 million was invested by Unitholders during the six months ended June 30, 2008 and a total of 1.7 million Trust Units were issued at an average price of $7.37 per Trust Unit. Effective March 2008, no Trust Units are available under the optional cash purchase component of the DRIP until further notice.

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:

- 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;
- Base production forecasts;
- Current financial and physical forward natural gas sales contracts;
- Forward market for natural gas prices;
- Site reclamation and abandonment expenditures; and
- Working capital requirements.

Distributions for the second quarter of 2008 totaled $33.3 million or $0.30 per Trust Unit consisting of $0.10 per Trust Unit paid on May 15, June 16 and July 15.

PET anticipates that distributions and capital expenditures for the remainder of 2008 and 2009 will be funded by funds flow and proceeds from the Trust's DRIP plan; 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.

	Three months ended June 30		Six months ended June 30	
Distributions ($ thousands)	**2008**	2007	**2008**	2007
Cash flow from operating activities	**65,128**	65,999	**118,029**	132,948
Funds flow	**81,350**	72,669	**137,541**	138,266
Net earnings (loss)	**(55,365)**	9,218	**(141,025)**	(30,043)
Distributions	**33,343**	39,350	**66,452**	80,625
Excess of cash flow from operating activities over distributions	**31,785**	26,649	**51,577**	52,323
Excess of funds flow over distributions	**48,007**	33,319	**71,089**	57,641
Excess (shortfall) of net earnings (loss) over distributions	**(88,708)**	(30,132)	**(207,477)**	(110,668)

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 from 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 $31.8 million for the three months ended June 30, 2008 and $26.6 million for the three months ended June 30, 2007 compare to exploration and development expenditures on PET's cash flow statement of $14.9 million and $20.1 million for those periods, respectively. In periods where the excess of cash flows from operating activities over distributions is less than exploration and development expenditures, the shortfall is funded by proceeds from the Trust's DRIP program, additional bank borrowings and external financing activities as appropriate.

PET's excess of funds flow over distributions for the three and six months ended June 30, 2008 measured $48.0 million and $71.1 million, respectively compared to $33.3 million and $57.6 million, respectively for the three and six months ended June 30, 2007. PET's distributions are less than funds flow as the Trust retains a portion of its funds flow to finance capital expenditures and debt repayments. The Trust's payout ratio, which is the ratio of distributions to funds flow, was 41.0 percent in the current quarter as compared to 54.1 percent for the second quarter of 2007. 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.

The Trust has an excess of distributions over net earnings in all periods presented and distributions are likely to continue to exceed net earnings in future periods. PET does not typically compare distributions to earnings due to the significant impact of non-cash items on earnings, such as unrealized gains and losses on financial instruments 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.

2008 Outlook and Sensitivities

At current natural gas prices the Trust's monthly distribution is highly sustainable. As at August 6, 2008, the current actual and forward market for natural gas for July through December 2008 was $8.36 per GJ at AECO. The following table reflects PET's projected realized gas price, monthly funds flow and payout ratio at the current monthly distribution of $0.10 per Trust Unit for the last six months of 2008 at certain AECO natural gas price levels and incorporating the Trust's current financial hedges and physical forward sales contracts.

Funds flow sensitivity analysis	Average AECO Monthly Index Gas Price July to December 2008 ($/GJ)			
	$7.00	$8.00	$9.00	$10.00
Oil and natural gas production (MMcfe/d)	183	183	183	183
Realized gas price (1) ($/Mcfe)	7.53	8.08	8.63	9.19
Funds flow (2) ($million/month)	21.1	23.6	26.0	28.5
Per Trust Unit ($/Unit/month)	0.189	0.211	0.233	0.255
Payout ratio (2) (%)	53	47	43	39
Ending net bank debt ($million)	291	277	262	247
Ending net total debt ($million)	527	513	498	483
Ending net total debt to funds flow ratio (3) (times)	2.0	1.8	1.7	1.6

(1) PET's weighted average forward price on an average of 101,000 GJ/d for the period from July 1 to December 31, 2008 is $7.51 per GJ.

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

(3) Calculated as ending net total debt (including convertible debentures) divided by estimated 2008 annual funds flow.

The Trust's outlook and sensitivities assume operating costs of $1.70 per Mcfe, cash general and administrative expenses of $0.45 per Mcfe, capital expenditures of $52 million and an interest rate on bank debt of 5.1 percent for the second half of 2008.

OTHER SIGNIFICANT ACCOUNTING POLICIES AND NON-GAAP MEASURES

Payout ratio

Payout ratio refers to distributions 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 Mcfe of oil and 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 funds flow from operations, net earnings per Trust Unit or other measures of financial performance calculated in accordance with GAAP.

Total capitalization

Total capitalization is equal to net debt including convertible debentures plus market value of issued equity and is used by management to analyze leverage. Total capitalization as presented does not have any standardized meaning prescribed by 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.

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.

Working capital (deficiency)

Working capital and working capital deficiency are calculated by the Trust as current assets less current liabilities, excluding assets and liabilities relating to financial instruments, in order to analyze short-term cash requirements without including mark-to-market balances that may settle for significantly different amounts than those presented on the balance sheet. Working capital (deficiency) as presented does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of working capital (deficiency) for other entities.

INTERNAL CONTROLS

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. PET's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of June 30, 2008 that the Trust's disclosure controls and procedures are effective to provide reasonable assurance that material information related to PET, including its consolidated subsidiaries, is made known to them by others within those entities. During the three months ended June 30, 2008, there have been no changes in PET's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

NEW ACCOUNTING STANDARDS

The Canadian Institute of Chartered Accountants ("CICA") has released new accounting standards for implementation effective January 1, 2008, as follows:

a) Section 3031 – Inventories. The new standard replaces the previous inventories standard and prescribes certain methods for valuing inventories. The adoption of this standard has had no material impact on PET's consolidated financial statements.

b) Section 3862 – Financial Instruments - Disclosures and Section 3863 - Financial Instruments - Presentation. The new disclosure standard requires increased disclosure regarding the Trust's financial instruments, the risks associated with these instruments and how the risks are managed. The new presentation standard carries forward the former presentation requirements. The required disclosures are contained in Notes 1a) and 12 to the Trust's interim unaudited consolidated financial statements.

c) Section 1535 - Capital Disclosures. The new standard requires the Trust to disclose its definition of capital and its objectives, policies and processes for managing its capital structure. The required disclosures are contained in Note 12 to the Trust's interim unaudited consolidated financial statements.

INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

The Canadian Accounting Standards Board recently confirmed January 1, 2011 as the date 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.

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 and 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.

The Trust has identified key internal personnel with expertise to manage its transition to IFRS. During the first half of 2008, PET staff have been involved in external IFRS training and development by means of attending conferences, participating in special interest seminars, and focusing on numerous training sessions put on by various accounting service firms.

PET will actively monitor the effects of the IFRS conversion on information technology systems and internal controls over financial reporting.

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.

The critical accounting estimates employed by PET in the preparation of its consolidated financial statements are discussed in the MD&A for the year ended December 31, 2007. In addition, the following critical accounting estimate was used in the consolidated financial statements for the three months ended June 30, 2008.

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 value, 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Income taxes

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

In light of the foregoing, the Trust Tax Legislation has reduced the value of the Trust's units which increases the cost to PET of raising capital in the public capital markets for acquisition opportunities. PET's access to capital markets could also be affected by this legislation. In addition, the Trust Tax Legislation is expected to place PET and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity-level taxation. There can be no assurance that PET will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the Trust Tax Legislation.

Gas over bitumen issue

On July 24, 2007 the Alberta Energy and Utilities Board ("EUB") 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 EUB 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 EUB, 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.

Depletion of reserves

The Trust has certain unique attributes which differentiate it from some 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.

Other risks and uncertainties affecting PET's operations are substantially unchanged from those presented in the MD&A for the year ended December 31, 2007.

FORWARD-LOOKING INFORMATION

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

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

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

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

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

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

The above list of risk factors is not exhaustive. The forward-looking statements contained in this MD&A are made as at the date of this MD&A and PET does not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Additional information on PET, including the most recent filed annual report and annual information form, can be accessed from SEDAR at www.sedar.com or from the Trust's website at www.paramountenergy.com.

CONSOLIDATED BALANCE SHEETS

As at ($ thousands, unaudited)	June 30, 2008	December 31, 2007
Assets		
Current assets		
Accounts receivable	**$ 75,079**	$ 65,160
Marketable securities (note 3)	**1,613**	1,069
Financial instruments (notes 2 and 12)	**-**	18,447
	76,692	84,676
Property, plant and equipment (notes 4 and 5)	**1,042,424**	1,097,338
Goodwill	**29,129**	29,129
Financial instruments (notes 2 and 12)	**-**	1,564
	$ 1,148,245	$ 1,212,707
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 54,618**	$ 48,754
Distributions payable	**11,135**	10,956
Financial instruments (notes 2 and 12)	**121,261**	-
	187,014	59,710
Long term bank debt (note 7)	**321,757**	342,190
Gas over bitumen royalty adjustments (note 15)	**68,164**	59,593
Asset retirement obligations (note 11)	**195,998**	194,132
Convertible debentures (note 8)	**225,710**	224,135
Financial instruments (notes 2 and 12)	**8,363**	-
Non-controlling interest (note 6)	**1,986**	2,012
Unitholders' equity		
Unitholders' capital (note 9)	**1,096,895**	1,083,250
Equity component of convertible debentures (note 8)	**7,335**	7,338
Contributed surplus (note 10)	**10,599**	8,446
Deficit	**(975,576)**	(768,099)
	139,253	330,935
	$ 1,148,245	$ 1,212,707

See accompanying notes

Basis of presentation: note 1

Subsequent event: note 3

Commitments and contingency: notes 12, 13 and 15

INTERIM CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) AND DEFICIT

	Three Months Ended June 30		Six Months Ended June 30	
	2008	2007	**2008**	2007
($ thousands except per unit amounts, unaudited)		Restated		Restated
Revenue				
Natural gas	**$ 166,199**	$ 104,451	**$ 285,270**	$ 204,144
Royalties	**(29,301)**	(18,440)	**(47,030)**	(33,127)
Realized gain on financial instruments (notes 2 and 12)	**(11,867)**	19,610	**(9,060)**	33,901
Unrealized loss on financial instruments (notes 2 and 12)	**(70,385)**	(3,071)	**(149,635)**	(51,564)
Gas over bitumen revenue (note 15)	**1,087**	916	**1,880**	1,790
	55,733	103,466	**81,425**	155,144
Expenses				
Operating	**28,556**	21,717	**61,593**	47,106
Transportation costs	**3,731**	3,030	**7,325**	5,716
Exploration expenses	**1,997**	2,730	**5,658**	7,885
General and administrative (note 10)	**11,296**	7,021	**19,333**	11,775
Interest and other	**3,737**	5,584	**7,584**	8,727
Interest on convertible debentures	**4,593**	3,330	**9,167**	6,379
Gain on sale of property, plant and equipment	**-**	-	**(1,528)**	-
Depletion, depreciation and accretion	**57,195**	50,845	**113,395**	97,596
	111,105	94,257	**222,527**	185,184
Earnings (loss) before income taxes	**(55,372)**	9,209	**(141,102)**	(30,040)
Future income tax (note 14)	**-**	-	**-**	-
Current taxes	**-**	-	**-**	-
	-	-	**-**	-
Net earnings (loss) before non-controlling interest	**(55,372)**	9,209	**(141,102)**	(30,040)
Non-controlling interest (note 6)	**7**	9	**77**	(3)
Net earnings (loss)	**(55,365)**	9,218	**(141,025)**	(30,043)
Deficit, beginning of period	**(886,868)**	(669,947)	**(768,099)**	(619,748)
Change in accounting policy (note 2)	**-**	-	**-**	30,337
Distributions declared	**(33,343)**	(39,350)	**(66,452)**	(80,625)
Deficit, end of period	**(975,576)**	(700,079)	**(975,576)**	(700,079)
Accumulated other comprehensive income	**-**	-	**-**	-
Deficit and accumulated other comprehensive income, end of period	**$ (975,576)**	$ (700,079)	**$ (975,576)**	$ (700,079)
Earnings (loss) per Trust Unit (note 9(c))				
Basic and diluted	**$ (0.50)**	$ 0.10	**$ (1.27)**	$ (0.34)
Distributions per Trust Unit	**$ 0.30**	$ 0.42	**$ 0.60**	$ 0.90

See accompanying notes

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three Months Ended June 30		Six Months Ended June 30	
	2008	2007	**2008**	2007
($ thousands, unaudited)		Restated		Restated
Cash provided by (used for)				
Operating activities				
Net earnings (loss)	**$ (55,365)**	$ 9,218	**$ (141,025)**	$ (30,043)
Items not involving cash				
Depletion, depreciation and accretion	**57,195**	50,845	**113,395**	97,596
Trust Unit-based compensation	**1,974**	1,674	**3,028**	2,407
Unrealized loss (gain) on financial instruments	**70,385**	3,071	**149,635**	51,564
Gain on sale of property, plant and equipment	**-**	-	**(1,528)**	-
(Gain) loss on marketable securities	**(187)**	1,177	**(544)**	1,177
Non-cash interest expense on convertible debentures	**823**	608	**1,646**	1,147
Non-controlling interest	**(7)**	(9)	**(77)**	3
Gas over bitumen royalty adjustments	**5,116**	3,897	**8,571**	8,003
Expenditures on asset retirement obligations	**(1,190)**	166	**(2,906)**	(1,665)
Change in non-cash working capital	**(13,616)**	(4,648)	**(12,166)**	2,759
Cash flow provided by operating activities	**65,128**	65,999	**118,029**	132,948
Financing activities				
Issue of Trust Units	**132**	240,958	**3,832**	244,865
Distributions to Unitholders	**(28,934)**	(34,349)	**(57,586)**	(69,516)
Issue of convertible debentures	**-**	72,000	**-**	72,000
Change in bank debt	**(10,062)**	143,899	**(20,433)**	160,366
Change in non-cash working capital	**(3,945)**	251	**(795)**	(2,514)
	(42,809)	422,759	**(74,982)**	405,201
	$ 22,319	$ 488,758	**$ 43,047**	$ 538,149
Investing activities				
Acquisition of properties and corporate assets	**$ (318)**	$ (451,113)	**$ (780)**	$ (456,377)
Exploration and development expenditures	**(14,923)**	(20,115)	**(58,343)**	(79,175)
Proceeds on sale of property and equipment	**610**	1,037	**6,992**	3,090
Change in non-cash working capital	**(7,688)**	(18,567)	**9,084**	(5,687)
	$ (22,319)	$ (488,758)	**$ (43,047)**	$ (538,149)
Change in cash	**-**	-	**-**	-
Cash, beginning of period	**-**	-	**-**	-
Cash, end of period	**$ -**	$ -	**$ -**	$ -
Interest paid	**$ 10,957**	$ 4,380	**$ 15,329**	$ 7,658
Taxes paid	**-**	-	**-**	-

See accompanying notes

NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(dollar amounts in $ thousands Cdn except as noted)

1. BASIS OF PRESENTATION AND ACCOUNTING POLICIES

These interim consolidated financial statements of Paramount Energy Trust ("PET" or "the Trust") have been prepared by management under the successful efforts method of accounting in accordance with Canadian generally accepted accounting principles ("GAAP") following the same accounting principles and methods of computation as the consolidated financial statements for the year ended December 31, 2007 except as described in note 1 a) below. Certain of the disclosures provided below are incremental to those included with the annual consolidated financial statements. The specific accounting principles used are described in the annual consolidated financial statements of the Trust appearing on pages 38 through 39 of the Trust's 2007 annual report and should be read in conjunction with these interim financial statements.

The Trust has restated its comparative consolidated statements of earnings (loss) and deficit, and its consolidated statements of cash flows for the three and six month periods ended June 30, 2007 by $3.1 million in respect of adjustments to stock-based compensation expense.

2. Significant New Accounting Disclosures – Financial Instruments

Effective January 1, 2008, the Trust adopted the accounting requirements for CICA Handbook Sections 3862 ''Financial Instruments – Disclosure'', 3863 ''Financial Instruments – Presentation'', and 1535 ''Capital Disclosures''. Disclosure and presentation requirements for financial instruments are intended to provide further information on the significance of financial instruments to the entity's financial position, performance and funds flows. The Trust has presented and disclosed the nature and extent of the risks arising from financial instruments and how the entity manages such risks. Capital disclosure requirements provide an overview of the Trust's objectives, policies and processes for managing its capital structure. Adjustments to the consolidated financial statements for the three and six month periods ended June 30, 2008 have been made in accordance with the transitional provisions for these new standards. Refer to disclosure in note 12 relating to each of the above standards.

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition all financial instruments, including derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and financial liabilities measured at amortized cost. The Trust has designated its financial instruments into the following categories applying the indicated measurement methods:

Financial instrument	Category	Measurement method
Marketable securities	Held for trading	Fair value
Financial instrument assets and liabilities	Held for trading	Fair value
Accounts receivable	Loans and receivables	Amortized cost
Accounts payable and accrued liabilities	Loans and receivables	Amortized cost
Distributions payable	Loans and receivables	Amortized cost
Long term bank debt	Loans and receivables	Amortized cost
Convertible debentures	Financial liabilities	Amortized cost

Convertible debentures are classified as debt on the balance sheet with a portion of the proceeds allocated to equity. The debt component has been measured based on amortized cost. The Trust will assess at each reporting period whether each financial asset, other than those classified as held for trading, is impaired. An impairment loss, if any, is included in net earnings.

The Trust has entered into certain financial derivative and fixed-price physical delivery sales contracts ("physical sales contracts") in order to reduce its exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Trust has not designated its financial derivative or physical sales contracts as effective accounting hedges, even though the Trust considers all commodity contracts to be effective economic hedges. As a result, all financial derivative contracts and physical sales contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized as "unrealized gains and losses on financial instruments" on the Trust's statement of earnings. Settlements of financial derivative contracts are recognized in realized gains and losses on financial instruments and settlements of physical sales contracts are recognized in oil and natural gas revenue at the time each transaction under a contract is settled.

The Trust measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value. The Trust continuously evaluates all new material contracts for existence of embedded derivatives. No material embedded derivatives have been identified throughout the course of these evaluations. Costs incurred to issue convertible debentures are recorded against the related financial liability. The Trust has not incurred any other material costs pertaining to the acquisition of financial assets or liabilities.

3. CHANGE IN ACCOUNTING POLICY

On January 1, 2007, the PET adopted the new Canadian accounting standards for financial instruments. Prior periods have not been restated.

At January 1, 2007, the following adjustments were made to the balance sheet to adopt the new standards:

Changes to balance sheet accounts	**At January 1, 2007**
Financial instrument asset – current	$ 25,768
Financial instrument asset – long term	4,764
Other assets	(5,419)
Increase in assets	$ 25,113
Convertible debentures	$ 5,224
Deficit	(30,337)
Increase in liabilities and reduction in deficit	$ (25,113)

a) Financial instruments

The Trust uses financial instruments and non-financial derivatives, such as fixed-price commodity sales contracts requiring physical delivery of the underlying commodity, to manage the price risk attributable to anticipated sale of petroleum and natural gas production.

The Trust accounts for its commodity sales contracts requiring physical delivery as non-financial derivatives. Prior to adoption of the new standards, physical receipt and delivery contracts did not fall within the scope of the definition of a financial instrument. Accordingly, the fair values of these financial instruments as at January 1, 2007 were recorded as an asset on the Trust's balance sheet with an offsetting credit to deficit. Changes in fair value of these financial instruments from January 1, 2007 to December 31, 2007 as well as changes in fair values of financial forward natural gas and foreign exchange contracts between January 1, 2007 and December 31, 2007 were recorded in earnings. Financial forward natural gas and foreign exchange contracts have been accounted for as derivatives since January 1, 2006 and as such the changes in the fair value of these contracts have been recorded to earnings since that time.

b) Convertible debenture issue costs

Costs related to the issuance of the Trust's convertible debentures (see note 8) are netted against the carrying value of the convertible debentures and amortized into earnings over the life of the convertible debentures using the effective interest rate method. Prior to January 1, 2007, transaction costs were recorded as deferred charges in other assets and recognized in net earnings on a straight-line basis over the life of the convertible debentures. On adoption, issue costs were adjusted to reflect the application of the effective interest rate method since the date of issue of the related convertible debentures.

4. MARKETABLE SECURITIES

At June 30, 2008 marketable securities were comprised of a $1.6 million investment in Cordero Energy Inc. ("Cordero"), a publicly traded oil and gas company. The increase in market value of the investment of $0.2 million and $0.5 million for the three and six month periods ended June 30, 2008 have been included in interest and other expense on the statement of earnings (loss). On July 4, 2008, Cordero entered into an agreement to sell all of its outstanding common shares to another publicly traded oil and gas company in exchange for a combination of cash and common shares of the acquirer. The offer valued the Cordero shares at $5.50 per share.

5. PROPERTY, PLANT AND EQUIPMENT

	June 30, 2008	December 31, 2007
Petroleum and natural gas properties	**$ 2,022,047**	$ 1,971,066
Asset retirement costs	**175,638**	175,679
Corporate assets	**3,278**	2,617
	2,200,963	2,149,362
Accumulated depletion and depreciation	**(1,158,539)**	(1,052,024)
	$ 1,042,424	$ 1,097,338

Property, plant and equipment at June 30, 2008 included $144.9 million (December 31, 2007 - $142.9 million) currently not subject to depletion and $30.4 million (2007 - $30.4 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.

6. ACQUISITIONS

On June 26, 2007 PET closed the acquisition of a private oil and gas company and concurrent sale of certain net assets of the acquiree to a third party (the "Birchwavy Acquisition") for cash consideration of $391.8 million, plus $17.6 million in respect of working capital and acquisition costs of $3.8 million. The Birchwavy Acquisition was funded through the issuance of $250.5 million in subscription receipts which were converted into Trust Units upon closing of the acquisition (see note 9), $75.0 million in 6.5% convertible debentures (see note 8) and existing credit facilities. The acquisition was accounted for using the purchase method of accounting. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. The Trust has not yet finalized its determination of the assets acquired and the liabilities assumed, and therefore the purchase price and the allocation of such to the acquired assets and liabilities are subject to change.

Cash consideration	$	391,800
Cash paid for net working capital		17,580
Acquisition costs		3,800
Cash consideration paid	$	413,180
Property, plant and equipment	$	449,014
Cash and cash equivalents		23,032
Accounts receivable		19,313
Other assets		2,026
Accounts payable and accrued liabilities		(24,364)
Asset retirement obligation		(55,841)
Cash consideration paid	$	413,180

On April 30, 2007 the Trust closed the acquisition of producing petroleum and natural gas properties and assets in Northeast Alberta (the "Craigend/Radway/Stry Acquisition") for an aggregate purchase price of $45.2 million. The acquisition was financed through existing credit facilities.

7. NON-CONTROLLING INTEREST

In August of 2006 PET completed an internal restructuring whereby certain assets (the "Severo Assets") were transferred to Severo Energy Corporation ("Severo"), a private company, and a newly formed partnership, the Severo Energy Partnership ("Severo Partnership"). In addition, PET provided a $10.5 million promissory note to Severo in exchange for additional common shares.

In consideration for the assets and the promissory note PET received 15,000,908 common shares of Severo priced at $2.00 per share and a onr percent partnership interest in Severo Partnership which has subsequently been transferred back to Severo. Concurrent with the transaction Severo completed a private placement at $2.00 per share to employees and consultants for proceeds of $2.0 million representing approximately 6 percent of the issued common shares of Severo. As of June 30, 2008 PET owned approximately 93 percent of Severo.

PET has nominated two representatives of the two person Board of Directors of Severo. Since the Trust has retained effective control of Severo, the results, assets and liabilities of this entity have been included in these financial statements. The non-PET ownership interests of Severo are shown as non-controlling interest.

8. BANK AND OTHER DEBT

At June 30, 2008 PET had a revolving credit facility with a syndicate of Canadian chartered banks (the "Credit Facility") with a borrowing base of $400 million consisting of a demand loan of $390 million and a working capital facility of $10 million. The Trust's lenders have completed their semi-annual borrowing base redetermination, resulting in a reconfirmation of the Trust's borrowing base at $400 million through October 31, 2008 and an extension of the facility agreement until May 25, 2009. 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. In addition to amounts outstanding under the Credit Facility, PET has outstanding letters of credit in the amount of $4.38 million. Collateral for the Credit Facility is provided by a floating-charge debenture covering all existing and acquired property of the Trust, excluding the Severo assets, as well as unconditional full liability guarantees from all subsidiaries in respect of amounts borrowed under the Credit Facility.

Advances under the Credit Facility are made in the form of Banker's Acceptances ("BA"), prime rate loans or letters of credit. In the case of BA advances, interest is a function of the BA rate plus a stamping fee based on the Trust's current ratio of debt to cash flow. In the case of prime rate loans, interest is charged at the lenders' prime rate. The effective interest rate on outstanding amounts at June 30, 2008 was 4.19 percent.

In addition, Severo has a demand credit facility with a Canadian chartered bank in the amount of $10 million. At June 30, 2008 Severo had not yet drawn on this facility.

9. CONVERTIBLE DEBENTURES

The Trust's 6.5% convertible unsecured subordinated debentures issued on June 20, 2007 ("6.5% Convertible Debentures") mature on June 30, 2012, bear interest at 6.5% per annum paid semi-annually on June 30 and December 31 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 6.5% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $14.20 per Trust Unit. During the six month period ended June 30, 2008, $0.1 million of 6.5% Convertible Debentures were converted, resulting in the issuance of 5,281 Trust Units.

The Trust's 6.25% convertible unsecured subordinated debentures issued on April 6, 2006 ("2006 6.25% Convertible Debentures") mature on April 30, 2011, bear interest at 6.25% per annum paid semi-annually on April 30 and October 31 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 2006 6.25% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $23.80 per Trust Unit.

The Trust's 6.25% convertible unsecured subordinated debentures issued on April 26, 2005 ("2005 6.25% Convertible Debentures") mature on June 30, 2010, bear interest at 6.25% per annum paid semi-annually on June 30 and December 31 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 2005 6.25% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $19.35 per Trust Unit.

The Trust's 8% convertible unsecured subordinated debentures ("8% Convertible Debentures") mature on September 30, 2009, bear interest at 8.0% per annum paid semi-annually on March 31 and September 30 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 8% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $14.20 per Trust Unit.

At the option of PET, the repayment of the principal amount of the convertible debentures may be settled in Trust Units. The number of Trust Units to be issued upon redemption by PET will be calculated by dividing the principal by 95 percent of the weighted average trading price for ten trading days prior to the date of redemption. The interest payable may also be settled with the issuance of sufficient Trust Units to satisfy the interest obligation.

	8% Series Amount	2005 6.25% Series Amount	2006 6.25% Series Amount	6.5% Series Amount	Total Amount
Balance, December 31, 2006	$ 5,866	$ 55,038	$ 96,487	-	$ 157,391
June 20, 2007 Issuance	-	-	-	75,000	75,000
Issue costs	-	-	-	(3,000)	(3,000)
Portion allocated to equity	-	-	-	(2,812)	(2,812)
Change in accounting policy (see note 2)	(112)	(1,436)	(3,676)	-	(5,224)
Accretion of non-cash interest expense	-	116	731	291	1,138
Amortization of debenture issue fees	47	436	863	320	1,666
Converted into Trust Units	-	-	(24)	-	(24)
Balance, December 31, 2007	$ 5,801	$ 54,154	$ 94,381	$ 69,799	$ 224,135
Accretion of non-cash interest expense		58	365	250	673
Amortization of debenture issue fees	23	220	431	299	973
Converted into Trust Units	-	-	-	(71)	(71)
Balance, June 30, 2008	**$ 5,824**	**$ 54,432**	**$ 95,177**	**$ 70,277**	**$ 225,710**
Fair value, June 30, 2008	**$ 5,955**	**$ 55,271**	**$ 99,442**	**$ 72,677**	**$ 233,345**
Number of debentures outstanding, June 30, 2008	**5,866**	**55,271**	**99,972**	**74,925**	**236,034**

A reconciliation of the equity component of convertible debentures is provided below:

Balance, as at December 31, 2006	$ 4,527
Converted into Trust Units	(1)
Equity component of 6.5% Convertible Debentures	2,812
Balance, as at December 31, 2007	$ 7,338
Converted into Trust Units	(3)
Balance, as at June 30, 2008	**$ 7,335**

10. UNITHOLDERS' CAPITAL

a) Authorized

Authorized capital consists of an unlimited number of Trust Units and an unlimited number of Special Voting Units. No Special Voting Units have been issued to date.

b) Issued and Outstanding

The following is a summary of changes in Unitholders' capital:

Trust Units	Number of Units	Amount
Balance, December 31, 2006	85,186,011	$ 812,174
Units issued pursuant to Unit offering	20,450,000	250,513
Units issued pursuant to Unit Incentive Plan	244,500	1,665
Units issued pursuant to Bonus Rights Plan	981	12
Units issued pursuant to Distribution Reinvestment Plan	3,674,876	32,882
Units issued pursuant to conversion of debentures	1,050	25
Issue costs on convertible debentures converted to Trust Units	-	(1)
Trust Unit issue costs	-	(14,020)
Balance, December 31, 2007	109,557,418	1,083,250
Units issued pursuant to Unit Incentive Plan	25,000	229
Units issued pursuant to Bonus Rights Plan	56,559	778
Units issued pursuant to Distribution Reinvestment Plan	1,705,359	12,574
Units issued pursuant to conversion of debentures	5,281	75
Issue costs on convertible debentures converted to Trust Units	-	(2)
Trust Unit issue costs	-	(9)
Balance, June 30, 2008	**111,349,617**	**$ 1,096,895**

c) Per Unit Information

Basic per unit amounts are calculated using the weighted average number of Trust Units outstanding during the three and six months ended June 30, 2008 of 111,055,014 and 110,611,981 (2007 – 89,226,509 and 87,530,690 respectively). PET uses the treasury stock method for incentive and bonus rights in instances where market price exceeds exercise price thereby impacting the diluted calculations. In computing diluted per unit amounts for the three and six months ended June 30, 2008, nil Trust Units respectively were added to the basic weighted average number of Trust Units outstanding (2007 – nil net Trust Units respectively) for the dilutive effect of incentive rights and convertible debentures. In computing diluted per unit amounts for the three and six month periods ended June 30, 2008, 3,414,250 and 3,597,875 incentive rights respectively, as well as 12,746,393 potentially issuable Trust Units through the Convertible Debentures (see note 8) were excluded as the exercise and conversion prices were out of the money at June 30, 2008 (for both the three and six months ended June 30, 2007 – 3,587,175 incentive rights, 12,751,675 potentially issuable Trust Units through the Convertible Debentures).

d) Redemption Right

Unitholders may redeem their Trust Units at any time by delivering their Trust Unit certificates to the Trustee of PET. Unitholders have no rights with respect to the Trust Units tendered for redemption other than a right to receive the redemption amount. The redemption amount per Trust Unit will be the lesser of 90 percent of the weighted average trading price of the Trust Units on the principal market on which they are traded for the ten day period after the Trust Units have been validly tendered for redemption and the "closing market price" of the Trust Units.

In the event that the aggregate redemption value of Trust Units tendered for redemption in a calendar month exceeds $100,000 and PET does not exercise its discretion to waive the $100,000 limit on monthly redemptions, PET will not use cash to pay the redemption amount for any of the Trust Units tendered for redemption in that month. Instead, PET will pay the redemption amount for those Trust Units, subject to compliance with applicable laws including securities laws of all jurisdictions and the receipt of all applicable regulatory approvals, by the issuance of promissory notes of PET ("Notes") to the tendering Unitholders.

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

11. INCENTIVE PLANS

a) Unit Incentive Plan

PET has adopted a Unit Incentive Plan ("Unit Incentive Plan") which permits the Administrator's Board of Directors to grant non-transferable rights to purchase Trust Units ("Incentive Rights") to its and affiliated entities' employees, officers, directors and other direct and indirect service providers. The purpose of the Unit Incentive Plan is to provide an effective long-term incentive to eligible participants and to reward them on the basis of PET's long-term performance and distributions. The Administrator's Board of Directors will administer the Unit Incentive Plan and determine participants, numbers of Incentive Rights and terms of vesting. The grant price of the Incentive Rights ("Grant Price") shall equal the per Trust Unit closing price on the trading date immediately preceding the date of the grant, unless otherwise permitted.

Prior to June 30, 2007, the exercise price of the Incentive Rights ("Exercise Price") was, subject to certain limitations, reduced by deducting from the Grant Price the aggregate amounts of all distributions on a per Trust Unit basis that PET pays its Unitholders after the date of grant which represented a return of more than 2.5 percent per quarter on PET's consolidated net property, plant and equipment on its balance sheet at each calendar quarter end ("Base Return"). The Exercise Price will be adjusted on a quarterly basis and in no case may it be reduced to less than $0.001 per Trust Unit. Effective June 30, 2007, the Base Return was reduced to nil in the formula for calculating Exercise Price reductions. The Incentive Rights are only dilutive to the calculation of earnings per Trust Unit if the exercise price is below the market price of the Trust Units. During the three and six month periods ended June 30, 2008 the Trust recorded $2.0 million and $3.0 million respectively in Trust Unit compensation ($1.7 million and $2.4 million respectively for the three and six month periods ended June 30, 2007).

At June 30, 2008 PET had 7.1 million Unit Incentive and Bonus Rights issued and outstanding relative to the 11.1 million (10 percent) of total Trust Units outstanding reserved under the Unit Incentive and the Bonus Rights Plans (see note 10 (b)). As at June 30, 2008, 851,500 Incentive Rights granted under the Unit Incentive Plan had vested but were unexercised (247,625 as of June 30, 2007).

PET used the binomial lattice option pricing model to calculate the estimated fair value of the outstanding Incentive Rights issued on or after January 1, 2003. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

		Year of grant
	2008	2007
Distribution yield (%)	**0.0**	0.0 – 6.3
Expected volatility (%)	**30.0 – 32.0**	28.5 – 29.5
Risk-free interest rate (%)	**2.66 – 3.46**	3.86 – 4.65
Expected life of Incentive Rights (years)	**3.75**	3.75 – 4.5
Vesting period of Incentive Rights (years)	**4.0**	4.0
Contractual life of Incentive Rights (years)	**5.0**	5.0
Weighted average fair value per Incentive Right on the grant date	**$ 2.37**	$ 1.82

Incentive Rights	**Average exercise price**	**Incentive Rights**
Balance, December 31, 2006	$ 14.60	3,644,675
Granted	6.97	3,661,875
Exercised	0.31	(244,500)
Forfeited	13.23	(371,175)
Balance, December 31, 2007	11.02	6,690,875
Granted	8.61	335,000
Exercised	5.29	(25,000)
Forfeited	5.75	(13,500)
Balance, June 30, 2008	**$ 10.94**	**6,987,375**

The following summarizes information about Incentive Rights outstanding at June 30, 2008 assuming the reduced exercise price described above:

Range of exercise prices	**Number outstanding at June 30, 2008**	**Weighted average contractual life (years)**	**Weighted average exercise price/Incentive Right**	**Number exercisable at June 30, 2008**	**Weighted average exercise price/Incentive Right**
$ 4.29	50,000	0.4	$ 4.29	37,500	$ 4.29
$ 4.98 - $ 10.67	4,204,250	3.6	6.44	241,500	5.47
$ 11.01 - $ 15.08	1,974,000	2.2	12.40	359,000	12.33
$ 15.15 - $ 18.58	759,125	2.7	16.45	213,500	17.08
Total	6,978,375	2.9	$ 10.94	851,500	$ 11.22

A reconciliation of contributed surplus is provided below:

Balance, as at December 31, 2006	$ 5,760
Trust Unit-based compensation expense	4,287
Transfer to Unitholders' capital on exercise of Incentive Rights	(1,590)
Transfer to Unitholders' capital on exercise of Bonus Rights	(11)
Balance, as at December 31, 2007	8,446
Trust Unit-based compensation expense	3,028
Transfer to Unitholders' capital on exercise of Incentive Rights	(97)
Transfer to Unitholders' capital on exercise of Bonus Rights	(778)
Balance, as at June 30, 2008	**$ 10,599**

b) Bonus Rights Plan

PET has implemented a bonus rights plan ("Bonus Rights Plan") for certain officers, employees and direct and indirect service providers of the Administrator ("Service Providers"). Rights to purchase Trust Units ("Bonus Rights") granted under the Bonus Rights Plan may be exercised during a period (the "Exercise Period") not exceeding three years from the date upon which the Bonus Rights were granted. The Bonus Rights vest over two years. At the expiration of the Exercise Period, any Bonus Rights which have not been exercised shall expire and become null and void. Upon vesting, the plan participant is entitled to receive the vested units plus an additional number of Trust Units equal to the value of distributions on PET's Trust Units as if the Trust Units were invested in PET's Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan") accrued since the grant date.

For the three and six month periods ended June 30, 2008, $0.8 million in compensation expense was recorded in respect of the Bonus Rights granted (three and six month periods ended June 30, 2007 - $0.5 million).

The following table shows changes in the Bonus Rights outstanding under the Bonus Rights Plan:

	Bonus Rights
Balance, December 31, 2006	37,805
Granted	45,668
Exercised	(981)
Forfeited	(1,193)
Additional grants for accrued distributions	12,120
Balance, December 31, 2007	93,419
Granted	110,315
Exercised	(56,559)
Additional grants for accrued distributions	9,066
Balance, June 30, 2008	**156,241**

12. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated based on PET's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods. PET has estimated the net present value of its total asset retirement obligations to be $196.0 million as at June 30, 2008 based on an undiscounted total future liability of $363.9 million. These payments are expected to be made over the next 25 years with the majority of costs incurred between 2015 and 2020. PET used a credit adjusted risk free rate of 7.0 percent to calculate the present value of the asset retirement obligation.

The following table reconciles the Trust's asset retirement obligations:

	June 30, 2008	December 31, 2007
Obligation, beginning of year	**$ 194,132**	$ 109,437
Obligations incurred	**1,487**	11,212
Obligations acquired	**-**	65,408
Obligations disposed	**(3,595)**	-
Expenditures for obligations during the period	**(2,906)**	(2,597)
Accretion expense	**6,880**	10,672
	$ 195,998	$ 194,132

13. FINANCIAL RISK MANAGEMENT

The Trust has exposure to the following risks from its use of financial instruments:

- Credit risk
- Liquidity risk
- Market risk

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Trust's risk management framework. The Board has implemented and monitors compliance with risk management policies.

The Trust's risk management policies are established to identify and analyze the risks faced by PET, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Trust's activities.

a) Credit Risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Trust's receivables from joint venture partners and petroleum and natural gas marketers.

Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Trust's policy to mitigate credit risk associated with these balances is to create marketing relationships with large, well established purchasers with high credit ratings. The Trust historically has not experienced any collection issues with its petroleum and natural gas marketing receivables. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, the receivables are generally from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs, the risk of unsuccessful drilling and oil and gas production; in addition, further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Trust does not typically obtain collateral from oil and natural gas marketers or joint venture partners; however, the Trust does have the ability in some cases to withhold production or amounts payable to joint venture partners in the event of non-payment.

The Trust manages the credit exposure related to marketable securities by monitoring the performance and financial strength of the investments and the liquidity of the securities being held.

During the period credit risk did not have any impact on the change in fair value of financial liabilities classified as held for trading.

The carrying amount of accounts receivable and marketable securities represents the maximum credit exposure. The Trust's allowance for doubtful accounts as at June 30, 2008 is $4.0 million. The entire amount of the allowance pertains to the working capital component of the Birchwavy Assets acquired in 2007 and was included as part of the purchase price equation (see note 5). The amount of the allowance was determined by assessing the probability of collection for each past due receivable related to the acquisition. The Trust is currently involved in negotiations with the seller and the joint venture partners involved in an effort to recover the full amount of the receivables in question. The total amount of receivables past due 90 days amounted to $12.8 million, as at June 30, 2008 and pertains primarily to Birchwavy assets. As at the balance sheet date, as a mitigating factor to the credit exposure, the Trust has $4.1 million payable to counterparties from which the Trust holds past due receivables.

b) Liquidity Risk

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they are due. The Trust's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Trust's reputation.

The Trust prepares annual capital expenditure budgets which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Trust has a revolving credit facility as outlined in note 7. The lender reviews the Trust's borrowing base on a semi-annual basis. The following are the contractual maturities of financial liabilities and associated interest payments as at June 30, 2008:

Contractual repayments of financial liabilities (1)	Total	2008	2009-2012	Thereafter
Accounts payable and accrued liabilities	$ 65,753	$ 65,753	$ -	$ -
Long term bank debt – principal	321,757	-	321,757	-
Convertible debentures – principal (2)	236,034	-	236,034	-
Total	$ 623,544	$ 65,753	$ 557,791	$ -

(1) Financial instrument liabilities are based on a mark-to-market calculation as of the balance sheet date and as such, future contractual repayments are uncertain. As a result, PET has not included financial instruments as financial liabilities in the above repayments schedule.

(2) Assuming repayment of principal is not settled in Trust Units, at the option of PET.

Interest payments on financial liabilities	Total	2008	2009-2012	Thereafter
Interest payment on bank debt(1)	$ 25,615	$ 6,741	$ 18,874	$ -
Interest on convertible debentures(2)	43,326	7,352	35,974	-
Total	$ 68,941	$ 14,093	$ 54,848	$ -

(1) Assuming revolving feature of the credit facility is not extended and calculated at the June 30, 2008 effective interest rate of 4.19%, assuming a constant debt level equivalent to the balance at June 30, 2008.

(2) Assuming payment of interest is not settled in Trust Units, at the option of PET.

c) Market Risk

Market risk is the risk that changes in market prices such as foreign exchange rates, commodity prices, and interest rates will affect the Trust's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Trust utilizes both financial derivatives and physical delivery sales contracts to manage market risks related to commodity prices. All such transactions are conducted in accordance with the Trust's Risk Management Policy, which has been approved by the Board of Directors.

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. The majority of the Trust's oil and natural gas sales are denominated in Canadian dollars. Due to the fact that the demand for oil and natural gas is substantially driven by the demand in the United States, the Trust's exposure to US dollar foreign exchange risk is indirectly driven by the price of oil and natural gas. From time to time the Trust also uses foreign exchange contracts to mitigate the effects of fluctuations in exchange rates on the Trust's cash flows. The Trust does not consider its direct exposure to foreign currency exchange rate risk to be significant; refer to commodity price risk analysis below. As at June 30, 2008 the Trust had no outstanding forward foreign exchange rate contracts.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by the world economic events that dictate the levels of supply and demand. The Trust has attempted to mitigate commodity price risk through the use of various financial derivative and physical delivery sales contracts. The Trust's policy is to enter into financial and forward physical gas sales contracts up to a maximum of 50 percent of forecasted production volumes including gas over bitumen deemed production, as outlined in the Trust's risk management policy.

As at June 30, 2008, the Trust has physical natural gas sales contracts which are contingent on future market prices. These contracts are not classified as financial instruments due to the fact that the settlement price corresponds directly with fluctuations in natural gas prices.

The remainder of production not subject to derivative contracts or fixed volume, non-derivative physical sales contracts is settled monthly with counterparties based on future monthly actual production and future monthly settlement prices.

For the period ended June 30, 2008 forward physical gas fixed-price sales contracts resulted in realized loss of $2.1 million that have been included in oil and natural gas revenue. In order to calculate these realized gains, PET compares the fixed price received to the AECO monthly index price and the NYMEX index.

Realized losses on financial instruments, including financial natural gas commodity contracts and foreign exchange price contracts, recognized in net earnings (loss) for three and six month periods ended June 30, 2008 were $11.9 million and $9.1 million respectively (realized gains of $19.6 million and $33.9 million for the three and six month periods ended June 30, 2007).

Natural gas commodity contracts

At June 30, 2008 the Trust had entered into financial and forward physical gas sales arrangements at AECO as follows:

Type of contract	PET sold/bought	Volumes at AECO (GJ/d)	Price ($/GJ)			Term
			Fixed	Floor	Ceiling	
Financial	sold	12,500	$9.897	-	-	July 2008
Financial	bought	(10,000)	$9.464	-	-	July 2008
Physical	sold	13,500	$10.312	-	-	July 2008
Physical	bought	(2,500)	$9.395	-	-	July 2008
Financial	sold	99,500	$7.407	-	-	July 2008 – October 2008
Financial	bought	(17,500)	$7.043	-	-	July 2008 – October 2008
Physical	sold	13,000	$6.827	-	-	July 2008 – October 2008
Physical	bought	(2,500)	$6.560	-	-	July 2008 – October 2008
Physical	sold	2,500	$7.450	-	-	July 2008 – December 2008
Physical	bought	(2,500)	$6.625	-	-	July 2008 – December 2008
Financial	sold	93,500	$7.785	-	-	November 2008 – March 2009
Financial	bought	(2,500)	$8.925	-	-	November 2008 – March 2009
Physical	sold	10,000	$8.223	-	-	November 2008 – March 2009
Physical	bought	(7,500)	$7.703	-	-	November 2008 – March 2009
Financial	sold	5,000	-	$7.000	$8.000	November 2008 – March 2009
Financial	sold	5,000	$11.110	-	-	January 2009
Financial	sold	60,000	$8.308	-	-	April 2009 – October 2009
Financial	bought	(20,000)	$7.619	-	-	April 2009 – October 2009
Physical	sold	5,000	$8.645	-	-	April 2009 – October 2009
Physical	bought	(5,000)	$8.445	-	-	April 2009 – October 2009
Financial	sold	12,500	$9.817	-	-	November 2009 – March 2010
Financial	bought	(2,500)	$8.140	-	-	November 2009 – March 2010

At June 30, 2008 the Trust had entered into financial and forward physical gas sales arrangements at NYMEX as follows:

Type of contract	PET sold/bought	Volumes at NYMEX (MMBTU/d)	Price (US$/MMBTU)	Term
Financial	sold	10,000	$ 7.700	July 2008 – October 2008
Financial	sold	2,500	$ 9.420	November 2008 – March 2009
Financial	bought	(2,500)	$ 9.260	November 2008 – March 2009

At June 30, 2008 the Trust had entered into financial and forward physical gas sales arrangements to fix the basis differential between the NYMEX and AECO trading hubs as follows. The price at which these contracts settle is equal to the NYMEX index less a fixed basis amount. Physical basis contracts represent commitments rather than contractual obligations.

Type of contract	PET sold/bought	Volumes at NYMEX (MMBTU/d)	Price (US$/MMBTU)	Term
Financial – basis	sold	5,000	$ (0.975)	July 2008 – October 2008
Financial – basis	bought	(5,000)	$ (1.045)	July 2008 – October 2008
Physical – basis	sold	37,500	$ (0.969)	July 2008 – October 2008
Physical – basis	bought	(37,500)	$ (1.200)	July 2008 – October 2008
Physical – basis	sold	5,000	$ (1.340)	November 2008 – March 2009
Physical – basis	bought	(5,000)	$ (1.435)	November 2008 – March 2009
Physical – basis	sold	17,500	$ (0.445)	April 2010 – October 2010
Physical – basis	bought	(17,500)	$ (0.731)	April 2010 – October 2010
Financial – basis	sold	15,000	$ (0.547)	April 2011 – October 2011
Financial – basis	bought	(15,000)	$ (0.550)	April 2011 – October 2011

At June 30, 2008 an unrealized loss of $149.6 million was recorded in the consolidated statement of earnings (loss) related to the change in fair value of financial and physical forward sales contracts from December 31, 2007 to June 30, 2008.

Commodity price sensitivity analysis

As at June 30, 2008, if future natural gas prices changed by $0.25 per GJ for AECO contracts and $0.25 per MMBTU for NYMEX contracts, with all other variables held constant, after tax net earnings for the period would have changed by $9.5 million. A potential increase in the natural gas price would result in a decrease to net earnings, while a decrease would lead to increased net earnings.

Mark to market sensitivity was based on published forward AECO and NYMEX prices. Gains and losses on NYMEX contracts were calculated based on the USD foreign exchange rate as at June 30, 2008.

Interest rate risk

The Trust utilizes a long-term debt credit facility which bears a floating rate of interest. Both of these financial liabilities are subject to interest rate risk. Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates, thereby affecting the Trust's operations.

Interest rate sensitivity analysis

For period ended June 30, 2008, if interest rates had been 1percent lower or higher the impact on earnings would be as follows:

Interest rate sensitivity	1% increase	1% decrease
Impact on net earnings	$ (900)	$ 900

The net earnings impact as a result of interest rate fluctuations is based on the assumption that the lender increases or decreases the fixed term BA rate consistently, based on a market interest rate change of 1 percent.

PET's convertible debentures were issued at a fixed interest rate and as such the debentures are not materially impacted by market interest rate fluctuations. To ensure accounts payable, including monthly distributions, are settled on a timely basis, the Trust manages liquidity risk as previously outlined in this note, thus limiting exposure to interest rate fluctuations and other penalties potentially resulting from past due payables.

The Trust had no interest rate swap or financial contracts in place as at or during the three months ended June 30, 2008.

Capital management

The Trust's policy is to maintain a strong capital base so as to retain investor, creditor and market confidence and to sustain the future development of the business. The Trust manages its capital structure and makes adjustments in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include unitholders' capital, bank debt, convertible debentures and working capital. In order to maintain or adjust the capital structure, the Trust may from time to time issue units or debt securities and adjust its capital spending and distributions to manage current and projected debt levels. This overall objective and policy for managing capital remains unchanged in 2008 from prior reporting periods.

The Trust monitors capital based on the ratio of net debt to annualized funds flow, calculated as follows for the three months ended June 30, 2008:

Net debt ($ thousands)	**June 30, 2008**
Bank debt	321,757
Convertible debentures, measured at principal amount	236,034
Working capital deficiency (surplus) (2)	(10,939)
Net debt	546,852
Cash flow provided by operating activities	65,128
Exploration costs (3)	1,416
Expenditures on asset retirement obligations	1,190
Changes in non-cash operating working capital	13,616
Funds flow	81,350
Annualized funds flow (1)	325,400
Net debt to annualized funds flow ratio (times) (1)	1.68

(1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in management's discussion and analysis.

(2) Working capital deficiency (surplus) excludes short-term financial instrument assets and liabilities related to the Trust's hedging activities.

(3) Certain exploration costs are added back 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 back to funds flow include seismic expenditures, dry hole costs and expired leases and are considered by PET to be more closely related to investing activities than operating activities.

As at June 30, 2008, the Trust's ratio of net debt to funds flow was 1.68 to 1. This ratio is monitored continuously by the Trust, and the targeted range of net debt to funds flow varies based on such factors as: acquisitions, commodity prices, projected cash flows, capital expenditure programs and timing of such programs. In order to facilitate the management of this ratio, the Trust prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

The Trust's unitholders' capital, convertible debentures and working capital are not subject to external restrictions. The Trust's credit facility is subject to lender's covenants with which PET was in compliance with at June 30, 2008.

The capital structure at June 30, 2008 was as follows:

Net debt	$ 546,852
Total equity (net of deficit)	139,253
Non-controlling interest	1,986
Total capital at June 30, 2008	**$ 688,091**

Fair value of financial instruments

The Trust's financial instruments as at June 30, 2008 and December 31, 2007 include marketable securities, accounts receivable, derivative contracts, accounts payable and accrued liabilities, distributions payable, bank debt and convertible debentures.

The fair values of marketable securities and convertible debentures are based on exchanged traded values in active markets as at the balance sheet date.

The fair value of accounts receivable, accounts payable, accrued liabilities and distributions payable approximate their carrying amounts due to their short-terms to maturity.

The fair value of derivative contracts is based on the difference between the fixed contract price or fixed basis differential and readily observable estimated, external forward market price curves as at the balance sheet date, based on natural gas volumes in executed contracts.

Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

14. OPERATING LEASES

a) Operating leases

As of June 30, 2008, the future minimum payments under office lease costs and related sublease recoveries under contractual agreements consisted of:

Operating Leases	
2008	$ 1,480
2009	2,956
2010	2,912
2011	728
Total commitment	$ 8,076

b) Pipeline commitments

The Trust has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada. As of June 30, 2008, the future minimum payments under pipeline commitments under contractual agreements consisted of:

Pipeline Commitments	
2008	$ 4,992
2009	6,195
2010	3,082
2011	2,681
2012	1,108
After 2012	2,178
Total commitment	$ 20,236

FUTURE INCOME TAXES

On June 12, 2007, Bill C-52 Budget Implementation Act, 2007 was enacted by the Canadian federal government, which contains legislation to change the tax treatment of publicly traded trusts in Canada. As a result, a new 31.5 per cent tax will be applied to distributions from Canadian public income trusts effective January 1, 2011. On October 30, 2007, the Finance Minister announced a reduction of the corporate income tax rate from 22.1 percent to 15 percent by 2012. The reductions will be phased in between 2008 and 2012. PET has not recorded a future income tax liability as a result of the Trust Tax Legislation being enacted. Based on production forecasts for PET's proved reserves included in the independent reserve report as at December 31, 2007, the tax values of the Trust's assets are projected to exceed the related book values by January 1, 2011, the date the direct tax on distributions within the Trust becomes effective.

15. GAS OVER BITUMEN ROYALTY ADJUSTMENTS

On October 4, 2004 the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas which provide a mechanism whereby the Government may prescribe 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 Alberta Energy and Utilities Board (the "AEUB") as a result of recent bitumen conservation decisions. Such royalty reduction was initially prescribed in December 2004, retroactive to the date of shut-in of the gas production.

If production recommences from zones previously ordered to be shut-in, gas producers may pay an incremental royalty to the Crown on production from the reinstated pools, along with Alberta Gas Crown Royalties otherwise payable. The incremental royalty will apply only to the pool or pools reinstated to production and will be established at one percent after the first year of shut-in increasing at one percent per annum based on the period of time such zones remained shut-in to a maximum of ten percent. The incremental royalties payable to the Crown would be limited to amounts recovered by a gas well operator through the reduced royalty.

At June 30, 2008 PET had received $88.1 million ($77.6 million at December 31, 2007) for cumulative gas over bitumen royalty adjustments to that date. Of this amount, $19.9 million has been recorded as revenue to date and $68.2 million has been recorded on the Trust's balance sheet.

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.

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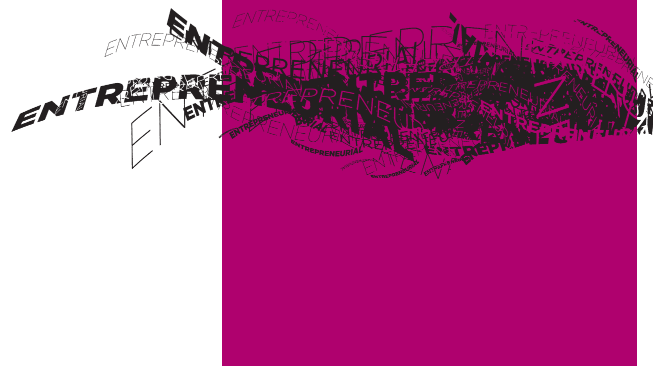
STOCK EXCHANGE LISTING | **TSX**

TRUST UNITS | PMT.UN

CONVERTIBLE DEBENTURES | PMT.DB
PMT.DB.A
PMT.DB.B
PMT.DB.C



CORPORATE INFORMATION

DIRECTORS

Clayton H. Riddell
Executive Chairman

Susan L. Riddell Rose
President, Chief Executive Officer and Director (4)

Karen A. Genoway
Independent Director (2) (3) (5)

Randall E. (Randy) Johnson
Independent Director (1) (3) (5)

Robert A. Maitland (1) (3) (5)
Independent Director

Donald J. Nelson
Independent Director (2) (4)

John W. (Jack) Peltier
Independent Director (1) (2) (4)

Howard R. Ward
Independent Director (3) (4) (5)

(1) Member of Audit Committee
(2) Member of Reserves Committee
(3) Member of Corporate Governance
(4) Member of Environmental, Health & Safety Committee
(5) Member of Compensation Committee

OFFICERS

Susan L. Riddell Rose
President, Chief Executive Officer and Director (4)

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

Gary C. Jackson
Vice President, Land, Legal and Acquisitions

Kevin J. Marjoram
Vice President, Engineering and Operations

Marcello M. Rapini
Vice President, Marketing

Roderick (Rick) P. Warters
Vice President, New Ventures and Geoscience

J. Christopher Strong
Acting Corporate Secretary, General Counsel

AUDITORS

KPMG LLP

BANKERS

Bank of Montreal

Canadian Imperial Bank of Commerce

The Bank of Nova Scotia

The Toronto-Dominion Bank

National Bank of Canada

ATB Financial

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

TRUSTEE REGISTRAR AND TRANSER AGENT

Computershare Trust Company of Canada

This report contains forward-looking information with respect to Paramount Energy Trust (PET). This forward looking information is based on certain assumptions that involve a number of risks and uncertainties and are not guarantees of future performance. Actual results could differ materially as a result of changes in PET's plans, changes in commodity prices, general economic, market and business conditions as well as production, development and operating performance, regulations and other risks associated with oil and gas operations,