PARAMOUNT
ENERGY TRUST

NEWS RELEASE

PARAMOUNT ENERGY TRUST RELEASES SECOND QUARTER 2005 FINANCIAL AND OPERATING RESULTS

Calgary, AB – August 8, 2005 - Paramount Energy Trust ("PET" or the "Trust") is pleased to release its results for the second quarter of 2005. Record production, continued strong commodity prices, the full effect of 2004 acquisition activities and the initial effect of the recent acquisition of shallow gas assets in Northeast Alberta (the "Northeast Alberta Acquisition") contributed to another quarter of exceptional financial results. As a result of the above factors, cash flow from operations increased 122 percent to $66.5 million for the three months ended June 30, 2005 from $29.9 million in the 2004 period. Further, the above factors have combined to enhance the sustainability of the Trust such that, assuming continued strength in commodity prices and future reinvestment in the Trust's base assets with success matching historical metrics, the Trust forecasts that its current distribution of $0.22 per Unit per month is sustainable for the foreseeable future.

SECOND QUARTER HIGHLIGHTS

- Production averaged 148.5 MMcf/d, representing an increase of 68 percent from the second quarter of 2004 despite the additional shut-in of over 12 MMcf/d of sales gas production on July 1, 2004 related to the gas over bitumen decisions. Including the deemed production volume related to the gas over bitumen financial solution, average daily production (actual and deemed) increased 75 percent to 171.6 MMcf/d from 98.2 MMcf/d in the second quarter of 2004. The significant increase is a result of several factors:
    1. The partial effect of the previously-announced Northeast Alberta Acquisition;
    2. The acquisitions of Cavell Energy Corporation and certain assets in the Athabasca area of Northeast Alberta ("Athabasca Assets") in the third quarter of 2004; and
    3. The positive results from PET's winter drilling program completed in the first quarter of 2005.

    PET's current actual daily production is approximately 164 MMcf/d excluding the gas over bitumen deemed production volume which is now approximately 22 MMcf/d, for a total current actual and deemed production of 186 MMcf/d.

- On May 17, 2005 PET closed the Northeast Alberta Acquisition. The net purchase price after closing adjustments totaled $272.3 million. The 100 percent natural gas assets acquired ("the Northeast Alberta Assets") are located in close proximity to the Trust's Northeast Alberta core areas but well outside the currently defined boundaries of the Alberta Energy and Utilities Board ("AEUB") gas over bitumen area of concern. Operating income related to the Northeast Alberta Assets totaled approximately $8.8 million for the quarter. Production from the Northeast Alberta assets has been included in PET's operational results from the closing date through June 30, 2005, resulting in an additional 23 MMcf/d of average natural gas production for the quarter. Current production from the Northeast Alberta assets is approximately 42 MMcf/d.

- Concurrent with the announcement of the Northeast Alberta Acquisition, PET entered into an agreement to sell on a bought deal basis 9,500,000 Subscription Receipts at a price of $16.85 each and $100 million of 6.25% convertible debentures to a syndicate of underwriters. The offering closed as scheduled on April 26, 2005, resulting in proceeds of $248 million net of underwriting fees. The Subscription Receipts were exchanged for an equivalent number of Trust Units on the closing of the Northeast Alberta Acquisition.

- Distributions payable for the quarter totaled $0.66 per Trust Unit, representing $0.22 per Trust Unit paid on May 16, June 15, and July 15, 2005, resulting in total distributions of $48.3 million for the period. PET's distributions as a percentage of cash flow were 72.6 percent. The Northeast Alberta Acquisition was a significant factor in reducing the Trust's payout ratio from first quarter 2005 levels. PET's payout ratio for the second half of 2005 is expected to be approximately 70 percent, reflecting the highly accretive nature of this acquisition.

- In April 2005 the Trust's major Unitholder enrolled approximately 19 million Trust Units in PET's industry-leading Distribution Reinvestment Plan ("DRIP"). Through the DRIP and optional cash purchase plans, a total of $15.3 million has been reinvested into the Trust by existing Unitholders in the second quarter. This represents a significant contribution of cost-effective equity capital for PET and reflects the alignment between the Trust and its Unitholders and overall confidence in the value of PET's Trust Units.

- The Trust is currently in the process of executing a $15 million capital expenditure program, planned for the remainder of 2005 and focused on production and reserve additions from its year-round access properties in southern Alberta and southwest Saskatchewan. This will bring anticipated capital expenditures for 2005 to $55 million in total with production additions expected to offset the natural production declines on the Trust's base assets.

- In April 2005, PET began deliveries of natural gas in accordance with its previously announced investment in a physical gas marketing limited partnership, Eagle Canada Limited Partnership ("Eagle"). The Trust has a five percent interest in Eagle. PET agreed to make available for delivery an average of 30,000 gigajoules/d of natural gas over a five year term to be marketed on PET's behalf by Eagle.

- Subsequent to the end of the quarter, $17.9 million of the Trust's outstanding 8% Convertible Debentures were converted into 1.26 million Trust Units at a conversion price of $14.20 per Unit.

Conference Call and Webcast

PET will be hosting a conference call and webcast at 9:00 a.m., Calgary time, Tuesday August 9, 2005 to review this information. Interested parties are invited to take part in the conference call by dialing one of the following telephone numbers 10 minutes before the start time: Toronto and area – 416 640-4127; outside Toronto – 866 250-4910. To participate in the live webcast please visit www.paramountenergy.com or www.newswire.ca/en/webcast/index.cgi. The webcast will also be archived shortly following the presentation.

Forward-Looking Information

This news release contains forward-looking information. Implicit in this information, particularly in respect of cash distributions, are assumptions regarding natural gas prices, production, royalties and expenses which, although considered reasonable by PET at the time of preparation, may prove to be incorrect. These forward-looking statements are 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, regulatory and business conditions as well as production, development and operating performance and other risks associated with oil and gas operations. There is no guarantee by PET that actual results achieved will be the same as those forecast herein.

About PET

Paramount Energy Trust is a natural gas-focused Canadian energy trust. PET's Trust Units are listed on the Toronto Stock Exchange ("TSX") under the symbol "PMT.UN". In addition, the Trust has two debenture listings on the TSX; "PMT.DB" which have a coupon rate of 8.0% and "PMT.DB.A" with a coupon rate of 6.25%. Further information with respect to PET can be found at its website at www.paramountenergy.com. The TSX has neither approved nor disapproved the information contained herein.

FOR ADDITIONAL INFORMATION, PLEASE CONTACT:

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FINANCIAL AND OPERATING HIGHLIGHTS	Three Months Ended June 30			Six Months Ended June 30		
($CDN thousands, except volume and per Trust Unit amounts)	**2005**	**2004**	**% Change**	**2005**	**2004 (3)**	**% Change**
FINANCIAL						
Revenue before royalties	100,234	49,904	101	176,580	101,136	75
Cash flow (1)	66,491	29,913	122	107,292	55,769	92
Per Trust Unit (2)	0.90	0.62	45	1.54	1.19	29
Net earnings (3)	11,357	5,016	126	13,510	7,013	93
Per Trust Unit (2)	0.15	0.11	36	0.19	0.15	27
Distributions	48,302	22,973	110	91,904	46,254	99
Per Trust Unit (4)	0.66	0.48	38	1.32	1.00	32
Payout ratio	72.6%	76.8%	(5)	85.7%	82.9%	3
Total assets	850,233	261,926	225	850,233	261,926	225
Net bank and other debt outstanding (5)	223,996	41,735	437	223,996	41,735	437
Convertible debentures	132,641	-	-	132,641	-	-
Total net debt (5)	356,637	41,735	755	356,637	41,735	755
Unitholders' equity	363,365	177,380	105	363,365	177,380	105
Capital expenditures						
Exploration and development	4,384	306	1,333	44,612	13,516	230
Acquisitions, net	257,825	-	-	284,623	32,939	764
Other	135	-	-	285	15	1,800
Net capital expenditures	262,344	306	85,633	329,520	46,470	609
TRUST UNITS OUTSTANDING (thousands)						
End of period	76,881	49,409	56	76,881	49,409	56
Weighted average	73,558	47,019	56	69,717	45,875	52
Incentive Rights outstanding	1,673	1,251	34	1,673	1,251	34
Trust Units outstanding at August 5, 2005	78,704					
OPERATING						
Production						
Total natural gas (Bcfe)	13.5	8.0	69	24.5	16.1	52
Daily average natural gas (MMcf/d)	148.5	88.2	68	135.3	88.5	53
Gas over bitumen deemed production (MMcf/d) (6)	23.1	10.0	131	23.3	10.0	133
Average daily (actual and deemed - MMcf/d)(6)	171.6	98.2	75	158.6	98.5	61
Per Trust Unit (cubic feet/d/Unit) (2)	2.33	2.09	11	2.27	2.15	6
Average prices						
Natural gas ($/Mcf), pre-hedging	7.41	6.57	13	7.04	6.44	9
Natural gas ($/Mcf), including hedging	7.42	6.22	19	7.21	6.28	15
LAND (thousands of net acres)						
Undeveloped land holdings	1,139	370	208	1,139	370	208
DRILLING						
Wells drilled (gross/net)						
Gas	17/3.2	-	-	51/31.0	13/12.7	292/144
Dry	1/1.0	-	-	4/4.0	-	-
Total	18/4.2	-	-	55/35.0	13/12.7	323/176
Success rate (% gross/% net)	94/76	-	-	93/89	100/100	(7)/(11)

(1) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent

operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital and include gas over bitumen royalty adjustments for shut-in production.

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

(3) Net earnings for 2004 have been restated to reflect the retroactive effect of a change in accounting policy related to Trust Unit-based compensation.

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

(5) Net debt includes net working capital (deficiency).

(6) The deemed production volume describes all gas shut-in or denied production pursuant to a Decision Report, corresponding AEUB Order or General Bulletin, or through correspondence in relation to an AEUB ID 99-1 application. 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.

CORPORATE

In the second quarter of 2005 PET significantly enhanced the sustainability of its business model. On May 17, 2005 PET completed the Northeast Alberta Acquisition for a net purchase price of $272.3 million. The 100 percent natural gas assets acquired are located in the Teepee, Marten Hills, Cherpeta and Darwin areas of Northeast Alberta, in close proximity to the Trust's Northeast Alberta Core Areas but well outside the defined boundaries of the AEUB gas over bitumen area of concern. As a result of the acquisition and a successful winter capital program, the Trust's current actual daily production is approximately 164 MMcf/d.

In connection with the Northeast Alberta Acquisition, PET issued 9,500,000 Trust Units at a price of $16.85 per Unit and $100 million of 6.25% convertible debentures for aggregate net proceeds of $248.1 million.

In April 2005 the Trust's major Unitholder enrolled approximately 19 million Trust Units in PET's industry-leading Distribution Reinvestment Plan ("DRIP"). With the reinvestment of distributions and optional cash purchases through the DRIP, a total of $15.3 million was invested into the Trust by existing Unitholders in the second quarter, representing participation from 23.2 million Trust Units on average or approximately 32 percent of the Trust's outstanding Units. The issuance of 970,835 Trust Units through the DRIP in the second quarter represents a significant contribution of cost-effective equity capital for PET and reflects the alignment between the Trust and its Unitholders and overall confidence in the value of PET's Trust Units.

The sustainability of the Trust's distributions is a function of its ability to offset base production declines with efficient capital spending on exploration and development of its assets. Sustainability occurs when such that total distributions plus capital spending are equal to or less than cash flow from operations while maintaining base production levels, excluding acquisitions, and assuming constant commodity prices.

At current production levels, commodity prices and netbacks, PET estimates cash flow for the second half of 2005 at approximately $150 million. Distributions at the current level of $0.22 per month would total $105 million for a payout ratio of 70 percent. Further, estimated cash flow would exceed the combination of distributions and capital expenditures, estimated at $15 million for the remainder of 2005, by $30 million.

Going forward the keys to the long-term sustainability of PET's business model are:

- A predictable production base;
- A low operating cost structure;
- An opportunity inventory for cost-effective production additions; and
- Undeveloped land to feed the prospect inventory.

PET's asset base is 100 percent shallow natural gas. Long production histories and well understood geological play types provide confidence in the extrapolation of future production estimates. High working interest and operatorship allow for control of the operating cost structure. Shallow gas opportunities are characterized by relatively low cost drilling and completion operations resulting in high deliverability which translate into low cost production additions. Historically, PET has been able to add production for less than $2.5 million per MMcf/d and expects to continue to do so for the foreseeable future given its extensive inventory of development and low exposure exploration opportunities and undeveloped land. This metric was achieved again in the first half of 2005 as the Trust added over 18 MMcf/d of production with capital expenditures of slightly less than $45 million.

OPERATIONS

Actual natural gas production for the second quarter of 2005 averaged 148.5 MMcf/d, a 22 percent increase from the first quarter of 2005, primarily due to the Northeast Alberta Acquisition as well as incremental production volumes from the winter capital program. Factoring in the deemed production volume related to the gas over bitumen financial solution, daily production (actual and deemed) averaged 171.6 MMcf/d in the second quarter of 2005.

CAPITAL EXPENDITURES, DRILLING AND ACQUISITIONS

Acquisitions

The Trust recorded net capital expenditures of $257.8 million on acquisitions in the second quarter of 2005. This was almost exclusively related to the Northeast Alberta Acquisition which closed May 17, 2005 for a net purchase price of $272.3 million less the initial deposit of $14.5 million paid in the first quarter.

Exploration and Development

Exploration and development expenditures totaled approximately $4.4 million in the second quarter with the initiation of the summer capital expenditure program, estimated at $15 million over the remainder of 2005. This program is concentrated in the Trust's Southern Core Area in southwest Saskatchewan and southern Alberta on lands that were acquired as part of the Cavell and Epact acquisitions in 2004 and 2003 respectively as well as in the Trust's East Side Core Area at Cold Lake and Craigend. The Trust drilled one well in Kirkpatrick and one well in West Central Saskatchewan (2.0 net wells) in addition to 16 wells (2.2 net wells) as part of the non-operated coal bed methane project at Craigmyle. A gathering system and compression facilities are also being installed at Craigmyle with first production expected to commence in September 2005. Since quarter end, the Trust initiated operations on a 10 well infill drilling program for Milk River production at Abbey, Saskatchewan.

GAS OVER BITUMEN ISSUE

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 additional royalty components to effect a reduction in the royalty calculated through the Crown royalty system for operators of gas wells which have been denied the right to produce by the AEUB as a result of recent bitumen conservation decisions. The Department of Energy issued an Information Letter 2004-36 ("IL 2004-36") which, in conjunction with the Regulation, sets out the details of the gas over bitumen financial solution.

The Trust's net deemed production volume for purposes of the royalty adjustment in the second quarter was 23.1 MMcf/d. In accordance with IL 2004-36, the deemed production volume related to wells shut-in on July 1, 2004 was reduced by 10 percent on July 1, 2005, and will be reduced by a further 10 percent at the end of every year of shut-in. Current deemed production is approximately 21.5 MMcf/d.

During the three months ended June 30, 2005, the Trust received $10.3 million in gas over bitumen royalty adjustments which have been recorded on its 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. Of this amount, $4.8 million is a retroactive adjustment related to wells which have been shut-in or denied production pursuant to a Decision Report, corresponding AEUB Order or General Bulletin, but for which the financial solution had not previously been received. The Department of Energy had requested further evidence which PET provided, and the financial solution was then granted retroactive to the shut-in dates. This brings cumulative royalty adjustments received to June 30, 2005 to $26.3 million. Royalty adjustments, although not included in earnings, are recorded as a component of funds from operations and as such are considered distributable income.

The final hearing with respect to the AEUB's bitumen conservation requirements commenced on June 14, 2005. PET filed detailed evidence supporting the resumption of production for six pools representing approximately 8.5 MMcf/d of production the Trust currently has shut-in pursuant to AEUB Orders and is actively participating in the hearing proceedings. PET also reiterated to the AEUB its continued objection to all zones that have been shut-in as a result of the interim hearing based on the new evidence that the Trust has submitted.

In addition, PET has reviewed the evidence submissions of all other parties and found that five additional producing wells, representing a total of less than 0.2 MMcf/d net to the Trust, have been further requested shut-in by other parties. As a result, PET concludes that it will have very little incremental gas production beyond that already shut-in subject to review at the final hearing. Any changes in productive status resulting from the final hearing should result in increased gas production for PET. The AEUB intends to make final decisions and issue final orders, when appropriate, confirming the production status of every interval within the scope of the Phase 3 proceedings, including those intervals whose production status is not contested in the final hearing. PET anticipates final decisions will be issued in late 2005 or early 2006 after the conclusion of the final hearing.

OUTLOOK

The recently acquired Northeast Alberta Assets are an excellent fit with PET's existing operations and significantly enhance the sustainability of the Trust's current level of distributions. Continued strength in natural gas markets has allowed the Trust to complement its winter capital program with additional capital activity in its year-round access areas further enabling the Trust to offset natural production declines by pursuing opportunities for additional production.

In order to lock in attractive economics on the Northeast Alberta Acquisition, PET added to its gas price risk management portfolio in the first and second quarters. The Trust currently has the following financial hedges in place:

Volumes at AECO (Gigajoules/day)("GJ/d")	**Price ($/GJ)**	**Term**
45,000 GJ/d	$ 7.05	July 2005 – October 2005
55,000 GJ/d	$ 8.19	November 2005 – March 2006
20,000 GJ/d	$ 8.01	April 2006 – October 2006

In addition, the Trust has sold forward physical natural gas as described below to partially fix the price that these financial hedges will settle against.

Volumes at AECO (Gigajoules/day)("GJ/d")	**Price ($/GJ)**	**Term**
68,500 GJ/d	$ 7.47	July 2005 – October 2005
11,500 GJ/d	$ 8.38	October 2005
5,000 GJ/d	$ 6.50 to $ 7.30	July 2005 – October 2005
75,000 GJ/d	$ 8.60	November 2005 – March 2006
20,000 GJ/d	$ 7.83	April 2006 – October 2006

SENSITIVITY ANALYSIS

Below is a table that demonstrates the sensitivity of PET's cash flow both monthly and annually to operational changes and changes in the business environment:

		Impact on Cash Flow per Trust Unit ($/Unit)	
	Change	**Annually**	**Monthly**
Business Environment			
Price per Mcf of natural gas (PET Avg.)	$ 0.25/Mcf	0.166	0.014
Operational			
Gas production volume	5 MMcf/d	0.126	0.010
Operating costs	$ 0.10/Mcf	0.075	0.006
Cash G&A expenses	$ 0.10/Mcf	0.075	0.006

These sensitivities assume operating costs of $1.10 per Mcf and cash general and administrative expenses of $0.15 per Mcf as per our forecast of these parameters for 2005.

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, 2005 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, 2005 and 2004, as well as the Trust's consolidated financial statements and accompanying notes and MD&A for the years ended December 31, 2004 and 2003. The date of this MD&A is August 5, 2005.

This MD&A contains forward-looking statements within the meaning of applicable securities laws. Forward-looking statements include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. The forward-looking statements in the MD&A include statements with respect to among other things, the Trust's business strategy, the Trust's intent to control marketing and transportation activities, reserve estimates, production estimates, hedging policies, asset retirement costs, the size of available tax pools, the Trust's credit facility, the funding sources for the Trust's capital expenditure program, cash flow estimates, environmental risks faced by the Trust's compliance with environmental regulations, commodity prices and the impact of the adoption of various Canadian Institute of Chartered Accountants Handbook Sections and Accounting Guidelines.

Although PET believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on them because the Trust can give no assurance that such expectations will prove to have been correct. There are many factors that could cause forward-looking statements to be incorrect including known and unknown risks and uncertainties inherent in the Trust's business. These risks include, but are not limited to; natural gas price volatility, exchange rate and interest rate fluctuations, availability of services and supplies, market competition, uncertainties in the estimates of reserves, the timing of development expenditures, production levels and the timing of achieving such levels, the Trust's ability to replace and expand oil and gas reserves, the sources and adequacy of funding for capital investments, future growth prospects and current and expected financial requirements of the Trust, the cost of future asset retirement obligations, the Trust's ability to enter into or renew leases, the Trust's ability to secure adequate production transportation, changes in environmental and other regulations, the ability to extend its debt on an ongoing basis, and general economic conditions. The Trust's forward-looking statements are expressly qualified in their entirety by this cautionary statement. We undertake no obligation to update our forward-looking statements except as required by law.

HIGHLIGHTS

	Three Months Ended June 30		**Six Months Ended June 30**	
($Cdn millions, except per Unit and volume data)	**2005**	**2004**	**2005**	**2004**
Cash flow [1]	$ 66.5	$ 29.9	$ 107.3	$ 55.8
Cash flow per Unit	$ 0.90	$ 0.62	$ 1.54	$ 1.19
Net earnings	$ 11.4	$ 5.0	$ 13.5	$ 7.0
Net earnings per Unit	$ 0.15	$ 0.11	$ 0.19	$ 0.15
Distributions	$ 48.3	$ 23.0	$ 91.9	$ 46.3
Distributions per Unit	$ 0.66	$ 0.48	$ 1.32	$ 1.00
Payout ratio (%)	72.6	76.8	85.7	82.9
Production (MMcf/d) [2]				
Actual daily average production	148.5	88.2	135.3	88.5
Gas over bitumen deemed production [3]	23.1	10.0	23.3	10.0
Total average daily (actual and deemed) [3]	171.6	98.2	158.6	98.5

(1) Before changes in non-cash working capital, includes gas over bitumen royalty adjustments.

(2) Production amounts are based on company interest before royalties.

(3) The deemed production volume describes all gas shut-in or denied production pursuant to a Decision Report, corresponding AEUB Order or General Bulletin, or through correspondence in relation to an AEUB ID 99-1 application. 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.

Natural gas revenue increased 101 percent to $100.2 million for the three months ended June 30, 2005 compared to $49.9 million for the three months ended June 30, 2004. Increased production volumes resulted in a $34.1 million increase in revenue while higher natural gas prices increased revenue by $16.2 million.

Realized natural gas prices increased by 19 percent for the three months ended June 30, 2005 to $7.42 per Mcf from $6.22 per Mcf in 2004. PET's blend of aggregator contracts, forward sales and AECO Monthly index and daily spot market sales resulted in a realized natural gas price of approximately 101 percent of the AECO average Monthly index for the second quarter of 2005 versus 86 percent for the comparable period in 2004. AECO average Monthly index prices increased 1 percent from $7.26 per Mcf for the three months ended June 30, 2004 to $7.34 per Mcf for the three months ended June 30, 2005. The increase in PET's gas prices exceeded the increase in the AECO average Monthly index price as the Trust had fixed the price on a portion of its production at prices below spot market prices for the second quarter of 2004. Before hedging, PET's realized natural gas price was $7.41 per Mcf for the three months ended June 30, 2005 compared to $6.57 per Mcf for the same period in 2004. Realized natural gas prices for the six months ended June 30, 2005 increased 15 percent to $7.21 per Mcf from $6.28 per Mcf in 2004.

For the three months ended June 30, 2005, PET's average royalty rate was 17.8 percent compared to 13.6 percent for the three months ended June 30, 2004. PET's average royalty rate for the six months ended June 30, 2005 was 18.4

percent as compared to 15.8 percent for the first half of 2004. The increase in the average royalty rates is primarily a result of the increase in the reference prices in 2005 compared to 2004, as well as a higher royalty rate for the Northeast Alberta Assets as the average production rate per well for the newly acquired assets is higher than that for the Trust's other assets.

Total production costs increased $6.8 million in the three months ended June 30, 2005 compared to the same period in 2004. Unit production costs were $1.08 per Mcf in the three months ended June 30, 2005 compared to $0.98 per Mcf for the second quarter of 2004. Unit production costs have increased in 2005 due to fixed operated costs related to the operation of additional plants and reduced throughput volumes in some of the plants due to the gas over bitumen shut-in of wells on July 1, 2004. PET's unit operating costs are typically highest during the first half of the year due to the winter-only access nature of the majority of its Northeast Alberta properties. Average operating costs are expected to decrease to less than $1.00 per Mcf for the remainder of the year. Full year 2005 operating costs are still anticipated to average $1.10 per Mcf.

Higher commodity prices combined with higher production volumes, offset by higher royalties and higher production and transportation costs resulted in a $31.3 million increase in operating income to $64.4 million for the three months ended June 30, 2005 from $33.1 million for the three months ended June 30, 2004.

($Cdn millions)	
Production increase	$34.1
Price increase	16.2
Royalty increase	(11.0)
Transportation cost increase	(1.2)
Operating cost increase	(6.8)
Increase in net operating income	$31.3

	Three Months Ended June 30		**Six Months ended June 30**	
Netbacks ($/Mcf)	**2005**	**2004**	**2005**	**2004**
Gross revenue	$ 7.42	$ 6.22	$ 7.21	$ 6.28
Royalties	(1.32)	(0.84)	(1.33)	(0.99)
Operating costs	(1.08)	(0.98)	(1.28)	(1.15)
Transportation costs	(0.25)	(0.26)	(0.26)	(0.27)
Operating netback	4.77	4.14	4.34	3.87
General and administrative (1)	(0.28)	(0.27)	(0.26)	(0.24)
Interest (1) (2)	(0.29)	(0.08)	(0.25)	(0.11)
Capital taxes	(0.01)	-	(0.01)	-
Exploration expenses (1)	(0.04)	(0.06)	(0.06)	(0.05)
Gas over bitumen royalty adjustments	0.77	-	0.62	-
Cash flow netback	$ 4.92	$ 3.73	$ 4.38	$ 3.47

(1) Excluding non-cash expenses.
(2) Includes interest on bank debt and convertible debentures.

General and administrative expenses were $4.3 million for the three months ended June 30, 2005 compared to $2.4 million in 2004. The scale of PET's operations increased significantly with the acquisitions consummated during 2004 and with the Northeast Alberta Acquisition in May 2005. Cash general and administrative expenses on a unit-of-production basis were $0.28 per Mcf for the three months ended June 30, 2005 as compared to $0.27 per Mcf in 2004. For the six months ended June 30, 2005 general and administrative expenses totaled $6.7 million as compared to $4.3 million for the comparable period in 2004. For the second quarter of 2005 a non cash charge of $0.6 million related to Unit Incentive Right compensation costs was included in general and administrative expenses compared to $0.7 million for the same period in 2004.

Interest expense totaled $4.1 million for the three months ended June 30, 2005, as compared to $0.7 million for the comparable period in 2004. Interest expense has increased due to the debt financing of portions of the Cavell Energy Corp. and Athabasca Assets acquisitions in second half of 2004 as well as the Northeast Alberta Acquisition. Interest expense has also increased due to higher coupon rates on the Trust's convertible debentures, as compared to the interest rates on bank debt.

Gas over bitumen royalty adjustments totaled $10.3 million for the three months ended June 30, 2005. Of this amount, $4.8 million was a retroactive adjustment in respect of wells which had been shut-in on September 1, 2003 but for which compensation had not been received.

The above factors combined to increase cash flow from operations by 122 percent, to $66.5 million for the three months ended June 30, 2005 from $29.9 million in the 2004 period. Cash flow per Trust Unit increased 45 percent to $0.90 from $0.62 per Trust Unit for the comparable quarter in 2004.

Exploration expenses increased to $10.1 million for the three months ended June 30, 2005 as compared to $0.5 million for the second quarter of 2004. The Trust completed $4.0 million in seismic programs during 2005, focusing on prospective low cost exploration and development opportunities in Northeast Alberta. PET also expensed $5.6 million of expired leases during the period, the majority of which were acquired with the Athabasca and Marten Hills assets in 2004.

Depletion, depreciation and accretion (“DD&A”) expense increased from $24.1 million in the second quarter of 2004 to $34.4 million in 2005 due to increased production volumes offset somewhat by a reduction in the Trust’s depletion rate. PET’s depletion rate decreased from $3.00 per Mcf in the three months ended June 30, 2004 to $2.54 per Mcf in 2005. DD&A expense for the six months ended June 30, 2005 totaled $69.4 million or $2.83 per Mcf, as compared to $47.1 million or $2.92 per Mcf in 2004.

The Trust reported net earnings of $11.4 million in the second quarter of 2005 compared to net earnings of $5.0 million in the 2004 period. The increase of $6.4 million is primarily a result of increased cash flows due to higher production levels as compared to the second quarter of 2004, offset somewhat by higher exploration and DD&A expenses. Net earnings for the six months ended June 30, 2005 were $13.5 million, a 93 percent increase over 2004.

QUARTERLY INFORMATION

	Three Months Ended			
(thousands of dollars, except per Unit amounts)	**June 30, 2005**	**Mar 31, 2005**	**Dec 31, 2004**	**Sept 30, 2004**
Natural gas revenues before royalties	$ 100,234	$ 76,346	$ 79,665	$ 59,156
Net earnings (loss)	$ 11,357	$ 2,153	$ (29,685)	$ 4,781
Net earnings (loss) per Unit - basic	$ 0.15	$ 0.03	$ (0.46)	$ 0.08
- diluted	$ 0.15	$ 0.03	$ (0.46)	$ 0.08

	Three Months Ended			
(thousands of dollars, except per Unit amounts)	**June 30, 2004**	**Mar 31, 2004**	**Dec 31, 2003**	**Sept 30, 2003**
Natural gas revenues before royalties	$ 49,904	$ 51,232	$ 43,022	$ 48,812
Net earnings (loss)	$ 5,016	$ 1,997	$ (2,812)	$ 12,316
Net earnings (loss) per Unit - basic	$ 0.11	$ 0.04	$ (0.06)	$ 0.27
- diluted	$ 0.11	$ 0.04	$ (0.06)	$ 0.27

CAPITAL EXPENDITURES

	Three Months Ended June 30		**Six Months Ended June 30**	
($ thousands except where noted)	**2005**	**2004**	**2005**	**2004**
Exploration and development expenditures	$ 4,384	$ 306	$ 44,612	$ 13,516
Acquisitions	257,825	-	284,623	32,939
Other	135	-	285	15
Total capital expenditures	$ 262,344	$ 306	$ 329,520	$ 46,470

For the six months ended June 30, 2005, acquisitions totaled $284.6 million reflecting primarily the $272.3 million paid for the Northeast Alberta Assets. Exploration and development expenditures were $4.4 million for the current quarter as compared to $0.3 million for the 2004 period. PET’s capital expenditures are typically concentrated in the first quarter of the year due to the winter-only access nature of the Trust’s properties in Northeast Alberta. However, in the current year, PET initiated a more extensive summer capital expenditure program to exploit opportunities in its year-round access areas. As well, the Trust is participating in a non-operated coalbed methane project in the Craigmyle area of southern Alberta.

For the six months ended June 30, 2005, exploration and development expenditures totalled $44.6 million compared to $13.5 million for the same period in 2004. The Trust invested approximately $40 million in its winter-access properties in the first quarter with seismic programs, new drilling, completions and tie-ins, recompletions and facilities optimization work distributed throughout PET’s three core areas in Northeast Alberta.

LIQUIDITY AND CAPITAL RESOURCES

PET has a demand credit facility with a syndicate of Canadian chartered banks. The credit facility presently has a borrowing base of $310 million. The facility consists of a demand loan of $300 million and a working capital facility of $10 million. Bank debt was $230.6 million at June 30, 2005. In addition to amounts outstanding under the credit facility, PET has outstanding letters of credit in the amount of $2.87 million. Collateral for the credit facility is provided by a floating-charge debenture covering all existing and acquired property of the Trust as well as unconditional full liability guarantees from all subsidiaries in respect of amounts borrowed under the facility.

At June 30, 2005, PET had $100 million in 6.25% convertible debentures outstanding. These debentures were issued in April 2005 as partial funding for the Northeast Alberta Acquisition. The debentures mature on June 30, 2010, with interest payable semi-annually on June 30 and December 31, and are convertible into units of the Trust at a price of $19.35 per Trust unit. The fair value of the debentures at June 30, 2005 was $101.5 million.

PET also had $32.6 million of 8.00% convertible debentures outstanding at June 30, 2005. Approximately $1.6 million of these debentures were converted to Trust Units at a price of $14.20 per Trust Unit during the second quarter of 2005. The fair value of these debentures at June 30, 2005 was $39.0 million. Subsequent to the end of the quarter $17.9 million of the 8.00% convertible debentures were converted into 1,263,024 Trust Units.

Cumulative distributions for the second quarter of 2005 totaled $0.66 per Trust Unit. A distribution of $0.22 per Unit for the month of July, payable on August 15, 2005 was announced on July 20, 2005.

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, unlike the alternative "full cost accounting" method, generates a more conservative value for net earnings and cash flow as 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 cash flow results comparable to industry practice, the Trust reclassifies geological and geophysical costs as well as surrendered leases and abandonment costs from operating to investing activities.

Cash Flow

Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore it may not be comparable to the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. All references to cash flow throughout this MD&A are based on cash flow before changes in non-cash working capital.

Payout Ratio

Payout ratio refers to distributions measured as a percentage of cash flow for the period, and is used by management to analyze cash flow available for development and acquisition opportunities, as well as overall sustainability of distributions. Cash 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 Cash Flow Netbacks

Operating and cash flow netbacks are used by management in order to analyze margin and cash flow on each Mcf of natural gas production. Operating and cash 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 cash flow netbacks should not be viewed as an alternative to cash flow from operations, net earnings per Trust Unit or other measures of financial performance calculated in accordance with GAAP.

RISK AND UNCERTAINTIES

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.

Reserve Estimates

The reserve and recovery information contained in PET's independent reserve evaluation is only an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserve evaluator.

Cyclical and Seasonal Impact on Industry

The Trust's operational results and financial condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas producing regions.

Operational Matters

The operation of oil and gas wells involves a number of operating and natural hazards that may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damages to operating subsidiaries of the Trust and possible liability to third parties.

Acquisitions

The price paid for reserve acquisitions is based on engineering and economic estimates of the reserves made by independent engineers modified to reflect the technical views of management. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas, and operating costs, future capital expenditures, royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the working interests, management and the Trust.

Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil and natural gas reserves. PET will not be reinvesting cash flow in the same manner as other industry participants as one of the main objectives of the Trust is to maximize long-term distributions. Accordingly, absent sufficient capital reinvestment, PET's initial production levels and reserves will decline.

Additional Financing

In the normal course of making capital investments to maintain and expand the oil and natural gas reserves of the Trust, additional Trust Units are issued from treasury which may result in a decline in production per Trust Unit and reserves per Trust Unit. Conversely, to the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired.

Competitive Conditions

The Trust is a member of the petroleum industry which is highly competitive at all levels. The Trust competes with other companies and other energy trusts for all of its business inputs including exploitation and development prospects, access to commodity markets, property and corporate acquisitions and available capital.

Government Regulation Risk

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

Commodity Price, Foreign Exchange and Interest Rate Risk

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

- Economic conditions which influence the demand for natural gas and the level of interest rates set by the governments of Canada and the United States;
- Weather conditions that influence the demand for natural gas;
- Transportation availability and costs; and
- Price differentials among markets based on transportation costs to major markets.

Nature of Trust Units

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation.

CRITICAL ACCOUNTING ESTIMATES

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

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

Accounting for petroleum and natural gas operations

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

Reserve estimates

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

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

Impairment of petroleum and natural gas properties

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

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

Asset retirement obligations

The asset retirement obligations recorded in the consolidated financial statements are based on an estimate of the fair value of the total costs for future site restoration and abandonment of the Trust's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, the timing of asset retirement expenditures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgements that are subject to future revisions based on numerous factors including changing technology and political and regulatory environments.

Paramount Energy Trust
Consolidated Balance Sheets

As at	**June 30, 2005**	**December 31, 2004**
($ thousands)	(unaudited)	(restated, note 2)
Assets		
Current assets		
Accounts receivable	$ 47,679	$ 30,355
Property, plant and equipment (notes 4 and 5)	764,094	494,885
Goodwill (note 4)	29,129	29,698
Other assets (note 3)	9,331	1,773
	$ 850,233	$ 556,711
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 24,128	$ 21,674
Distributions payable	16,914	13,065
Bank and other debt (note 6)	230,633	171,698
	271,675	206,437
Gas over bitumen royalty adjustments (note 13)	26,306	11,200
Asset retirement obligations (note 10)	56,246	34,116
Convertible debentures (note 7)	132,641	38,419
Future income taxes	-	2,088
Unitholders' equity		
Unitholders' capital (note 8)	673,913	495,695
Contributed surplus (note 2)	3,551	4,461
Equity adjustments	(16,172)	(16,172)
Accumulated earnings	38,493	24,983
Accumulated distributions	(336,420)	(244,516)
	363,365	264,451
	$ 850,233	$ 556,711

See accompanying notes
Basis of presentation: note 1
Contingency: note 13

Paramount Energy Trust
Consolidated Statements of Earnings and Accumulated Earnings

	Three Months Ended June 30		Six Months Ended June 30	
	2005	**2004**	**2005**	**2004**
		(restated, note 2)		(restated, note 2)
($ thousands except per unit amounts, unaudited)				
Revenue				
Natural gas	$ 100,234	$ 49,904	$ 176,580	$ 101,136
Royalties	(17,861)	(6,782)	(32,500)	(16,021)
	82,373	43,122	144,080	85,115
Expenses				
Operating	14,639	7,868	31,243	18,533
Transportation costs	3,312	2,118	6,290	4,342
Exploration expenses	10,136	514	11,182	1,073
General and administrative (notes 2 and 9)	4,319	2,374	6,667	4,289
Gas over bitumen costs (note 13)	59	438	703	979
Interest	2,138	650	3,776	1,778
Interest on convertible debentures	2,011	-	2,678	-
Depletion, depreciation and accretion	34,372	24,144	69,366	47,108
	70,986	38,106	131,905	78,102
Earnings before income taxes	11,387	5,016	12,175	7,013
Future income tax reduction	-	-	1,519	-
Capital taxes	(30)	-	(184)	-
	(30)	-	(1,335)	-
Net earnings	11,357	5,016	13,510	7,013
Accumulated earnings net of distributions at beginning of period, as previously reported	(260,982)	(101,611)	(219,533)	(77,781)
Retroactive effect of change in accounting policy (note 2)	-	-	-	(2,546)
Accumulated earnings net of distributions at beginning of period, as restated	(260,982)	(101,611)	(219,533)	(80,327)
Distributions paid or payable	(48,302)	(22,973)	(91,904)	(46,254)
Accumulated earnings net of distributions at end of period	$ (297,927)	$ (119,568)	$ (297,927)	$ (119,568)
Earnings per Trust Unit (note 8(c))				
Basic and diluted	$ 0.15	$ 0.11	$ 0.19	$ 0.15
Distributions per Trust Unit	$ 0.66	$ 0.48	$ 1.32	$ 1.00

See accompanying notes

Paramount Energy Trust
Consolidated Statements of Cash Flows

	Three Months Ended June 30		Six Months Ended June 30	
	2005	**2004**	**2005**	**2004**
($ thousands, unaudited)		(restated, note 2)		(restated, note 2)
Cash provided by (used for)				
Operating activities				
Net earnings	$ 11,357	$ 5,016	$ 13,510	$ 7,013
Items not involving cash				
Gas over bitumen royalty adjustments	10,347	-	15,106	-
Depletion, depreciation and accretion	34,372	24,144	69,366	47,108
Trust Unit compensation	588	681	1,002	1,361
Future income tax reduction	-	-	(1,519)	-
Amortization of other assets	219	-	219	-
Exploration expenses	9,608	72	9,608	287
Funds from operations	66,491	29,913	107,292	55,769
Change in non-cash working capital	(10,938)	499	(10,779)	5,961
Decrease in other assets	(219)	-	(219)	-
	55,334	30,412	96,294	61,730
Financing activities				
Issue of Trust Units	154,253	48,838	156,787	49,408
Distributions to Unitholders	(37,630)	(22,973)	(78,547)	(46,254)
Issue of Convertible Debentures	96,000	-	96,000	-
Change in bank and other debt	16,567	(48,576)	58,935	(17,151)
Change in non-cash working capital	2,983	736	3,376	(1,023)
	232,173	(21,975)	236,551	(15,020)
	$ 287,507	$ 8,437	$ 332,845	$ 46,710
Investing activities				
Acquisition of investments	-	-	(1,243)	-
Acquisition of properties and corporate assets	(257,960)	-	(284,908)	(32,954)
Exploration and development expenditures	(4,384)	(306)	(44,612)	(13,516)
Proceeds on sale of property and equipment	1,036	-	1,036	-
Change in non-cash working capital and asset retirement obligation	(26,199)	(8,131)	(3,118)	(240)
	$(287,507)	$ (8,437)	$(332,845)	$ (46,710)
Interest paid	$ 3,164	$ 555	$ 6,935	$ 1,439
Taxes paid	$ 71	$ -	$ 105	$ -

See accompanying notes

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 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, 2004 except as described below. 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 52 through 54 of the Trust's 2004 annual report and should be read in conjunction with these interim financial statements.

2. CHANGE IN ACCOUNTING POLICY

Trust Unit-based compensation

On January 1, 2005 the Trust retroactively applied the fair value based method of accounting for Incentive Rights. Under the fair value based method of accounting, compensation expense is based on the fair value of the Unit-based compensation at the date of grant using a modified Black-Scholes option pricing model. Compensation expense associated with Rights is recognized in earnings over the vesting period. Consideration received upon the exercise of the Rights together with the amount previously recognized in contributed surplus is recorded as an increase in Unitholders' capital. The Trust has not incorporated an estimated forfeiture rate for Rights that will not vest. The Trust accounts for actual forfeitures as they occur.

Previously, the Trust applied the intrinsic value methodology due to the number of uncertainties regarding the reduction in the exercise price of the Rights which deemed a fair value calculation to be inappropriate. The Trust has now applied the fair value calculation as the variables have become more certain, including the life of the plan; future expected distributions and expected reduction in the Rights price where applicable.

Retroactive application of the fair value method resulted in a decrease in accumulated earnings and an increase in contributed surplus for 2003 of $0.2 million. Further, reported Trust Unit compensation expense for the year ended December 31, 2004 decreased by $2.8 million to $2.7 million with a corresponding increase in contributed surplus. The change in accounting policy had no effect on reported earnings for the three months ended June 30, 2004.

A reconciliation of contributed surplus resulting from adoption of the new policy is provided below:

Balance, as at January 1, 2004, as previously reported	$ 2,740
Adoption of fair value method	(194)
Balance, as at January 1, 2004, as restated	2,546
Trust Unit-based compensation expense, as previously reported	5,493
Reduction in Trust Unit-based compensation expense upon restatement	(2,771)
Transfer to Unitholders' capital on exercise of Incentive Rights	(807)
Balance, as at December 31, 2004, as restated	4,461
Trust Unit-based compensation expense	1,002
Transfer to Unitholders' capital on exercise of Incentive Rights	(1,912)
Balance, as at June 30, 2005	$ 3,551

3. OTHER ASSETS

	June 30, 2005	**December 31, 2004**
Convertible debenture issue costs	$ 5,088	$ 1,773
Investments	4,243	-
	$ 9,331	$ 1,773

Convertible debenture issue costs are amortized to earnings over the life of the debentures and reclassed to Unit issue costs as debentures are converted to Trust Units.

Investments include $3.0 million related to PET's 14 percent interest in Sebring Energy Inc. and $1.2 million related to the Trust's five percent interest in the Eagle Canada Limited Partnership. These investments are accounted for on a cost basis.

4. ACQUISITIONS

On May 17, 2005 the Trust closed the acquisition of producing natural gas properties in Northeast Alberta (the "Northeast Alberta Acquisition") for an aggregate purchase price of $272.3 million. The acquisition was financed through the issuance of 9,500,000 Trust Units for gross proceeds of $160.1 million in addition to the issuance of $100.0 million in 6.25% Convertible Extendible Unsecured Subordinated Debentures (see Note 7), and through existing credit facilities.

Property, plant and equipment acquired	$	285,594
Asset retirement obligation		(13,267)
Net purchase price	$	272,327

Goodwill recorded on the purchase of Cavell Energy Corporation has been reduced by $0. 5 million to reflect adjustments to tax pools balances at the closing date of the acquisition.

5. PROPERTY, PLANT AND EQUIPMENT

	June 30, 2005	December 31, 2004
Petroleum and natural gas properties	$ 1,270,511	$ 954,351
Asset retirement costs	51,292	30,787
Corporate assets	15,038	14,754
	1,336,841	999,892
Accumulated depletion and depreciation	(572,747)	(505,007)
	$ 764,094	$ 494,885

Property, plant and equipment costs at June 30, 2005 included $88.4 million (June 30, 2004 - $55.4 million) currently not subject to depletion.

6. BANK AND OTHER DEBT

PET has a revolving credit facility with a syndicate of Canadian Chartered Banks (the "Credit Facility"). The Credit Facility currently has a borrowing base of $310 million, consisting of a demand loan of $300 million and a working capital facility of $10 million. In addition to amounts outstanding under the Credit Facility, PET has outstanding letters of credit in the amount of $2.87 million. Collateral for the Credit Facility is provided by a floating-charge debenture covering all existing and acquired property of the Trust as well as unconditional full liability guarantees from all subsidiaries in respect of amounts borrowed under the 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, 2005 was 3.83%.

7. CONVERTIBLE DEBENTURES

The Trust's 8% convertible unsecured subordinated debentures (the "8% Convertible Debentures") mature on September 30, 2009, bear interest at 8.00% 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. During the six months ended June 30, 2005, $5.8 million of 8% Convertible Debentures were converted, resulting in the issuance of 406,886 Trust Units. Subsequent to June 30, an additional $17.9 million of 8% Convertible Debentures were converted resulting in the issuance of 1,263,024 Trust Units.

The Trust's 6.25% convertible unsecured subordinated debentures (the "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 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.

At June 30, 2005, the fair market value of the 8% Convertible Debentures was $39.0 million and the fair market value of the 6.25% Convertible Debentures was $101.5 million.

8. 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, 2003, as restated	44,638,376	$ 260,019
Units issued pursuant to Unit offerings	12,295,547	146,675
Units issued pursuant to corporate acquisition	6,931,633	78,674
Units issued pursuant to Unit Incentive Plan	153,875	1,371
Units issued pursuant to Distribution Reinvestment Plan	632,829	8,185
Units issued pursuant to conversion of Debentures PMT.DB	674,711	9,581
Issue costs on Convertible Debentures converted to Trust Units	-	(383)
Trust Unit issue costs	-	(8,427)
Balance, December 31, 2004	65,326,971	495,695
Units issued pursuant to Unit offerings	9,500,000	160,075
Units issued pursuant to Unit Incentive Plan	361,375	2,631
Units issued pursuant to Distribution Reinvestment Plan	1,285,280	20,401
Units issued pursuant to conversion of Debentures PMT.DB	406,886	5,778
Issue costs on Convertible Debentures converted to Trust Units	-	(229)
Trust Unit issue costs	-	(10,438)
Balance, June 30, 2005	76,880,512	$ 673,913

c) Per Unit Information

Basic earnings per Trust Unit were calculated using the weighted average number of Trust Units outstanding during the three months and six months ended June 30, 2005 of 73,558,001 and 69,716,530 respectively (2004 – 47,019,195 and 45,874,526, respectively). The Trust uses the treasury stock method where only "in the money" dilutive instruments impact the diluted calculations. In computing diluted earnings per Unit for the three and six month periods ended June 30, 2005, 553,036 and 545,657 Units respectively were added to the weighted average number of Trust Units outstanding for the dilutive effect of Incentive Rights (2004 - 247,637 and 176,165 respectively).

d) Redemption Right

Unitholders may redeem their Trust Units at any time by delivering their 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 10 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 (the "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 5 years after issuance.

9. UNIT INCENTIVE PLAN

At June 30, 2005 PET had granted 1,672,875 Unit Incentive Rights to purchase PET Trust Units to employees and directors of the administrator of PET under its Unit Incentive Plan.

At June 30, 2005 a total of 3,963,838 units had been reserved under the Unit Incentive Plan. As at June 30, 2005 12,500 Unit Incentive Rights granted under the Unit Incentive Plan had vested but were unexercised (100,000 as of June 30, 2004).

Unit Incentive Rights

	Average grant price	**Unit Incentive Rights**
Balance, December 31, 2004	$ 8.41	1,612,750
Granted	$ 16.82	461,500
Exercised	$ 5.38	(361,375)
Cancelled	$ 12.25	(40,000)
Balance, June 30, 2005	$ 11.29	1,672,875
Incentive Rights exercisable, end of period	$ 11.12	12,500

The following summarizes information about Incentive Rights outstanding at June 30, 2005:

Range of Exercise Prices	**Number outstanding at June 30, 2005**	**Weighted average contractual life (years)**	**Weighted average exercise price/ Right**	**Number exercisable at June 30, 2005**	**Weighted average exercise price/Right**
$0.64	482,750	3	$ 0.64	-	-
$8.43-$8.56	147,500	4	$ 8.50	12,500	$ 8.50
$9.24-$14.22	581,125	5	$ 10.50	-	-
$15.28-$17.17	461,500	5	$ 16.59	-	-
Total	1,672,875	4	$ 9.15	12,500	$ 8.50

The Trust recorded compensation expense in respect of Incentive Rights of $0.6 million for the three month period ended June 30, 2005, and $1.0 million for the six month period ended June 30, 2005 ($0.7 million for the three months ended June 30, 2004 and $ 1.4 million for the six months ended June 30, 2004).

PET used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding Unit Incentive Rights issued on or after January 1, 2003. The following assumptions were used to arrive at the estimate of fair value as at June 30, 2005:

	2005
Expected annual Unit Incentive Right's exercise price reduction	$ 1.48
Expected volatility	55.0%
Risk-free interest rate	3.78%
Expected life of Unit Incentive Rights (years)	5.0

10. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated by management based on the Trust's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Trust has estimated the net present value of its total asset retirement obligations to be $56.2 million as at June 30, 2005 based on a total future liability of $125.1 million. These payments are expected to be made over the next 25 years with the majority of costs incurred between 2010 and 2015. The Trust used a credit adjusted risk free rate of 7.82% to calculate the present value of the asset retirement obligation.

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

	June 30, 2005	**December 31, 2004**
Obligation, beginning of period	$ 34,116	$ 21,701
Increase in liabilities during the period	20,505	10,325
Accretion expense	1,625	2,090
	$ 56,246	$ 34,116

11. FINANCIAL INSTRUMENTS

Financial instruments

The Trust's financial instruments included in the consolidated balance sheet consist of accounts receivable, accounts payable and accrued liabilities, distributions payable and bank and other debt and convertible debentures. The fair values of these items approximated their carrying amounts at June 30, 2005 and December 31, 2004 due to their short-term nature, except for convertible debentures (see Note 7).

Natural gas commodity price hedges

At June 30, 2005, the Trust had entered into financial hedge arrangements as follows:

Type	Volume	Term	Fixed ($/GJ)	Floor ($/GJ)	Ceiling ($/GJ)
AECO fixed price	45,000 GJ/d	July 05 – Oct 05	$7.05	-	-
AECO fixed price	45,000 GJ/d	Nov 05 - Mar 06	$7.94	-	-
AECO fixed price	10,000 GJ/d	Apr 06 – Oct 06	$7.94	-	-

Had these contracts been settled on June 30, 2005, using forward prices in effect at that time, the mark-to-market settlement payment by PET would have totaled $3.2 million.

In addition, the Trust has sold forward physical natural gas to partially fix the price that these financial hedges will settle against. At June 30, 2005, the Trust had entered into physical gas sales arrangements as follows:

Type	Volume	Term	Fixed ($/GJ)	Floor ($/GJ)	Ceiling ($/GJ)
AECO collar	5,000 GJ/d	July - Oct 05	-	$6.50	$7.30
AECO fixed price	68,500 GJ/d	July 05 – Oct 05	$7.47	-	-
AECO fixed price	11,500 GJ/d	Oct 05	$8.38	-	-
AECO fixed price	60,000 GJ/d	Nov 05 - Mar 06	$8.40	-	-
AECO fixed price	10,000 GJ/d	Apr 06 – Oct 06	$7.51	-	-

12. COMMITMENTS

PET has committed to supply to Eagle Canada Limited Partnership for marketing on behalf of the Trust at market prices as directed by PET a minimum average of 30 MMcf/d of physical natural gas deliveries for a five year period commencing March 1, 2005.

13. GAS OVER BITUMEN ISSUE

The Alberta Energy and Utilities Board ("AEUB" or the "Board") issued General Bulletin 2003-28 ("GB 2003-28") on July 22, 2003. The AEUB continues to consider that gas production in pressure communication with associated potentially recoverable bitumen places future bitumen recovery at an unacceptable risk.

Following the completion of a Regional Geological Study by the AEUB and an interim hearing held in March 2004, the AEUB ordered the shut-in, effective July 1, 2004, of Wabiskaw-McMurray natural gas production in northeast Alberta totaling approximately 123 MMcf/d. PET currently has approximately 17.4 MMcf/d of sales gas shut-in pursuant to AEUB order. During the three and six month periods ended June 30, 2005 the Trust incurred $0.06 million and $0.7 million, respectively, in legal and consulting expenditures directly related to the gas over bitumen issue (2004 - $0.4 million and $1.0 million, respectively).

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 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 1 percent after the first year of shut-in increasing at 1 percent per annum based on the period of time such zones remained shut-in to a maximum of 10 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, 2005 PET had recorded $26.3 million for cumulative gas over bitumen royalty adjustments received to that date on the Trust's balance sheet. Royalty adjustments received are not included in earnings but are recorded as a component of funds from operations. As PET cannot determine if, when or to what extent the royalty adjustment may be repayable through incremental royalties if and when gas production recommences, the royalty adjustments are being excluded from earnings pending such determination.