PEYTO

Energy Trust

2005

Annual Report

Chairman's Message

For most unit holders of Peyto, the last year is probably remembered as a period of great volatility of the unit price, and a ten-month pause in production growth, which created anxiety in some circles about the Peyto business model. In the background during this period, the strength of the business model was being affirmed, and the basis of future growth was being built.

The unit price volatility reflected big swings in the price of natural gas. While there are other factors, short-term gas price trends are determined mostly by the weather. Last year's natural gas price swings were impacted by a fierce hurricane season followed by an unusually warm winter. This was set against a background of continuing high oil prices mostly because of geopolitical uncertainties.

The Directors and senior officers of Peyto spend little time discussing gas pricing. We are "price takers", who sleep well because we are a very low cost producer. We also know that gas is currently a cheaper (and cleaner) source of energy than oil.

I should note that when gas prices are rising, it is producers with high costs and low profit margins that experience the biggest percentage increases in cash flow. It is when gas prices decline that the quality of Peyto's assets is emphasized. Because of its high profit margins (and its "layered hedge program") Peyto should experience the smallest decrease in cash flow from current relatively weak gas prices.

The second reason for unit price volatility last year was the pause in production growth. Why did this happen? Firstly, Peyto was fighting the rapid declines of two hugely profitable wells at Kakwa. Secondly, an extended period of wet weather impacted the drilling program. Finally, the major property at Sundance was not operating optimally because of a lack of incremental gas processing capacity. Peyto has very long-term reserves, and thinks in terms of unusually long periods of time. Thus it is considered more important to get the location of a new gas plant right than to force one into a particular calendar quarter.

The first of two new gas plants started up on March 7, 2006 at Wildhay, and a second at Nosehill is scheduled to start up on August 1st. Both plants are easily expandable. Examination of the location of further gas processing capacity is ongoing.

The third important reason for unit price volatility in 2005 was the uncertainty regarding taxation of trusts initiated by then Finance Minister Goodale in August. Fortunately, the resolution a few months later was positive.

In 2005, your Board took satisfaction from the reserve life increase described fully elsewhere in this report. The cost of finding new reserves, albeit one of the lowest in the industry, was of some concern. While the Board is asking all the "hard questions" that must be asked, confidence in the Peyto business model remains high as reflected in the fact that Directors and senior officers continue to be substantial net buyers of units. As an aside, it is interesting to note that while there are many reasons for unit sales, taxes to pay being prominent among them, there is only one reason for buying units, and that is the expectation that they will go up in price.

Quite a lot of the Peyto Board's time in the last year has been taken up with the adoption of "best practices" in corporate governance. Much of the product of this work is filed on our website under "Corporate Governance". One of the more interesting features of this activity was the clear statement of Peyto's business objectives. These differ from the objectives of our competitors so it is valuable to reproduce them here:

Peyto defines itself as a "growth oriented energy trust".

Peyto's primary objective is to build the per unit value of its energy resources so that distributions to unit holders can be sustained and grown over time, despite the depleting nature of all oil and gas assets. This objective must be met in the context of an environment that fosters integrity and trust.

To achieve this primary objective, Peyto focuses its efforts to meet "best in sector" performance in the following areas:

- *returns on invested capital and on equity*
- *low cost structure*

- *long life reserves*
- *production growth per unit*
- *efficient replacement of production and reserves*

Fulfillment of this requires Peyto's professional staff to be freed of bureaucratic constraints, so their technical and entrepreneurial skills can be fully utilized.

Peyto is best served if the interests of its directors, executives and staff are aligned with those of the unit holders. Accordingly, Peyto encourages unit ownership by each group.

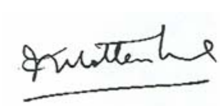
One of the consequences of being a "growth oriented energy trust" is that Peyto must build the team. In the last year, there was about a 50% increase in the head count. This was encouraging because it confirmed our view that Peyto would be able to attract talent in spite of the environment being as competitive as anyone can remember.

An able veteran in the industry succeeded the former VP Exploration. Another veteran joined to lead the Land team. A veteran reservoir engineer has just joined to assist in the evaluation of new opportunities. We had a seamless change of Chief Financial Officers. The Finance team was beefed up to address the demands of growth and governance requirements. Peyto added two new specialists, a Drilling Manager and a Completions Manager. It was desirable to have their expertise in-house when there is so much cost threatening inexperience out in the field. The exploration team was also expanded so that there is capacity to look at prospects away from Peyto's traditional areas. Finally, Peyto added an Investor Awareness officer to facilitate investor understanding of Peyto's unique value-building conduct of its affairs.

It will not be a surprise that Peyto's office space in Calgary was doubled last year.

For the time being, the Peyto team has been built up to a level where it will probably plateau for a while. The development of a team is, as I said last year, an evolutionary and dynamic process. Fine people with one skill set have left. Others with new skill sets have joined. Peyto's business model embraces necessary change. In particular, the objective is to create an ideal environment for smart experienced technical people to thrive. We also believe in bringing along younger members of the team so that they will be in a position to lead in the future.

Most of management's time is now being devoted to implementing the business model well. There is fine-tuning going on such as examination of the best pace of development. The Board is concentrating on thinking ahead so the needs and consequences of growth are well understood. At the same time, all aspects of Peyto's way of doing things are being examined freshly so that unit holders will be well served over the long term.



C. Ian Mottershead
Chairman of the Board

Report from the President

Peyto Energy Trust ("Peyto") is a leader in the exploration and development of natural gas in western Canada. By design, our core areas are located in Alberta's premier gas exploration area, the Deep Basin. We are known for our high quality assets and our ability to profitably find and develop new oil and natural gas reserves. We are proud to present our operating and financial results for the fourth quarter and 2005 fiscal year.

The following summarizes certain of the Trust's attributes at year end.

- Long reserve life – Proved 13.6 years, Proved Plus Probable 18.9 years
- High netback - $37.83/boe
- Low operating costs - $1.55/boe
- Low base general and administrative costs - $0.08/boe
- High operatorship - over 95% of production
- Low cash distribution ratio - 42% of fourth quarter 2005 funds from operations
- Low debt to funds from operations ratio – 0.83 (net debt, before provision for future performance based compensation, divided by annualized fourth quarter 2005 funds from operations)
- Distribution growth - distributions have been increased 5 times and are now 87% higher than when the trust was formed two and a half years ago
- Transparent capital structure - no convertible debentures, no exchangeable shares, no stock options, no warrants

The following summarizes certain performance highlights for the year.

- Value Creation – invested $358 million in capital and created $995 million of Proved and $1,159 million worth of Proved Plus Probable undiscounted reserve value
- Reserve life growth – the reserve life for every reserve category grew by over 10% from year over year
- Asset value growth per unit[(1)] – the net present value of the trust's proven producing oil and gas assets, discounted at 0%, 5% and 8%, all grew by approximately 54% per trust unit
- NPV Recycle ratio - Proved 2.8, Proved Plus Probable 3.2 (before change in future development capital)
- Distributions per unit[(1)] - increased by 36% from $1.02 in 2004 to $1.39 in 2005.
- Reserve growth per unit[(1)] - the most conservative category, proved producing reserves, grew 15% year over year
- Production growth – annual production increased 19% from 18,689 boe/d in 2004 to 22,219 boe/d in 2005
- Production growth per unit[(1)] - increased 10% year over year
- Funds from operations growth per unit[(1)] - increased 42% year over year
- Cost of new reserves (FD&A) - Proved $13.33/boe, Proved Plus Probable $11.18/boe (before change in future development capital)
- Recycle ratio - Proved 3.2, Proved Plus Probable 3.8 (before change in future development capital)
- Reserve replacement ratio - Proved 3.3, Proved Plus Probable 4.0

Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl).

[(1)] *Per unit results are adjusted for changes in net debt (including future performance based compensation) and equity. Net debt is converted to equity using the Dec 31 unit price of $25.39 for 2005 and $23.92 for 2004.*

	3 Months Ended Dec. 31		%	12 Months Ended Dec. 31		%
	2005	2004	Change	**2005**	2004	Change
Operations						
Production						
Natural gas (mcf/d)	**108,356**	97,968	*11%*	**106,701**	88,842	*20%*
Oil & NGLs (bbl/d)	**4,185**	4,360	*(4)%*	**4,436**	3,882	*14%*
Barrels of oil equivalent (boe/d @ 6:1)	**22,245**	20,688	*8%*	**22,219**	18,689	*19%*
Product prices						
Natural gas ($/mcf)	**10.55**	7.58	*39%*	**8.78**	7.38	*19%*
Oil & NGLs ($/bbl)	**58.43**	46.82	*25%*	**55.48**	42.66	*30%*
Operating expenses ($/boe)	**1.95**	1.03	*89%*	**1.55**	1.05	*48%*
Transportation ($/boe)	**0.70**	0.77	*(9)%*	**0.68**	0.70	*(3)%*
Field netback ($/boe)	**43.33**	32.90	*32%*	**37.83**	31.79	*19%*
General & administrative expenses ($/boe)	**0.05**	0.01	*400%*	**0.08**	0.12	*(33)%*
Interest expense ($/boe)	**0.91**	1.03	*(12)%*	**1.07**	1.01	*6%*
Financial ($000, except per unit)						
Revenue	**127,633**	87,127	*46%*	**431,695**	300,501	*44%*
Royalties (net of ARTC)	**33,522**	21,103	*59%*	**106,802**	71,089	*50%*
Funds from operations	**86,607**	60,334	*43%*	**296,970**	209,106	*42%*
Funds from operations per unit*	**0.85**	0.65	*31%*	**3.01**	2.28	*32%*
Cash distributions	**36,773**	26,443	*39%*	**136,648**	93,660	*46%*
Cash distributions per unit*	**0.36**	0.285	*26%*	**1.39**	1.02	*36%*
Percentage of funds from operations distributed	**42**	44	*(5)%*	**46**	45	*2%*
Earnings	**60,745**	(2,558)	-	**161,568**	73,782	*119%*
Earnings per diluted unit*	**0.60**	(0.03)	-	**1.64**	0.805	*104%*
Capital expenditures	**107,647**	76,953	*40%*	**358,454**	230,774	*55%*
Weighted average trust units outstanding*	**102,148,411**	92,494,022	*10%*	**98,576,640**	91,711,034	*7%*
As at December 31						
Net debt (before future compensation expense)				**287,885**	222,969	*29%*
Unitholders' equity				**421,831**	205,849	*105%*
Total assets				**944,927**	622,577	*52%*

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

	12 Months Ended Dec. 31	
	2005	2004
Net Earnings	**161,568**	73,782
Items not requiring cash:		
Non-cash provision for (recovery of) performance based compensation	**(18,271)**	15,945
Future income tax expense	**37,618**	25,558
Depletion, depreciation and accretion	**58,208**	40,880
Non-recurring items:		
Performance based compensation	**57,847**	52,941
Funds from operations (1)	**296,970**	209,106

(1) *Funds from operations*

Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before performance based compensation, non-cash and *non-recurring expenses. We believe that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future distributions may vary.*

Capital Expenditures

Net capital expenditures for 2005 totaled $358 million which was an increase of 55% from 2004. In 2005, 100% of the capital was invested to develop and produce new oil and gas reserves. The majority of our capital was spent to drill, case, complete and bring on production from new wells in the Deep Basin area. Capital was also spent to build 25 mmcf/d of gas processing capacity in the Cutbank and Kakwa areas. At Sundance, where we own and operate a 110 mmcf/d gas plant, we added additional facilities in order to minimize future downtime due to routine maintenance. Capital invested in new land and seismic evaluation increased from the previous year by 145%. The majority of the value associated with this land and seismic capital will be captured in future years when wells are drilled and reserves are produced. None of our 2005 capital was spent on acquisitions. The following table summarizes capital expenditures for the year.

	2005		**2004**		**Since Inception**	
Capital Expenditures	**($000)**	**% of Total**	**($000)**	**% of Total**	**($000)**	**% of Total**
Land	12,324	*3%*	3,975	*2%*	27,713	*2%*
Seismic	11,559	*3%*	5,768	*2%*	24,313	*3%*
Drilling & Completion – Exploratory & Development	274,360	*77%*	167,742	*73%*	701,943	*72%*
Production Equipment, Facilities & Pipelines	59,810	*17%*	49,898	*22%*	186,234	*19%*
Acquisitions & Dispositions	-	-	3,307	*1%*	30,856	*4%*
Office Equipment	401	-	84	-	857	-
Total	358,454	*100%*	230,774	*100%*	971,916	*100%*

During the year, we drilled or re-entered 120 gross (99 net) wells with a 100% success rate. The average depth of our wells was approximately 2,560m, which is 110m deeper than the year before. Of the wells drilled during 2005, over 77% were drilled to a depth deeper than our conventional Sundance Cardium well depth of 2,300m. We continue to evolve the mix of our drilling prospects to include deeper Cretaceous objective zones with the same reservoir characteristics as our original Cardium targets. Most of our wells have at least two and sometimes three prospective gas bearing zones for development. The following table summarizes the well activity for 2005.

Well Activity	**Drilled**		**Completed**		**Tied In/Brought On Production**	
Area	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Sundance	90	75	98	79	86	68
Kakwa	12	11	12	10	11	9
Cutbank	9	8	12	12	14	14
Berland	4	4	3	3	4	4
Other	5	1	1	0	0	0
Total	**120**	**99**	**126**	**104**	**115**	**95**

Since inception, we have invested a total of $972 million in capital. We have built a long life low cost natural gas business by investing significantly less value than we have created. Our strategy of building our own assets has allowed us to generate a three year compounded annual rate of return of 70% for our unitholders. Our drill bit approach takes raw material and turns it into a finished product. We have not had to dilute quality or sacrifice returns by acquiring marginal production and reserves. As illustrated in the following table, cash flow generated from our investments has played a dominant role, while net equity has played a relatively minor role in funding of our capital expenditures since Peyto started seven years ago.

Funding Sources for Capital Since Inception (from 1998 to 2005)	($000)	% of Total
Cash flow from projects found and developed by Peyto	598,126	62%
Net Equity (Equity issued of $357.1 million less Accumulated Distributions of $271.2 million)	85,905	9%
Net Debt (year end 2005 excluding future performance based compensation)	287,885	29%
Total Capital Expenditures	971,916	100%

Reserves

During 2005, the trust was again successful in adding high quality, long life reserves through the drill bit. The following table illustrates the change in reserve volumes and net present value of future cash flow, discounted at 5%, before income tax using variable pricing.

	As at December 31			
	2005	2004	% Change	% Change Debt Adjusted Per Unit
Reserves				
BOE 6:1 (mstb)				
Proved Producing	**87,881**	70,996	*24%*	*15%*
Total Proved	**110,802**	92,028	*20%*	*12%*
Proved + Probable Additional	**153,448**	129,506	*18%*	*10%*
Net Present Value ($million)				
Discounted at 5%				
Proved Producing	**2,113**	1,281	*65%*	*53%*
Total Proved	**2,539**	1,533	*66%*	*54%*
Proved + Probable Additional	**3,219**	1,983	*62%*	*51%*

Note: Based on the Paddock Lindstrom & Associates report effective December 31, 2005. The Paddock Lindstrom and Associates Ltd. price forecast is available at www.padlin.com. For more information on Peyto's reserves, we refer you to our Press Release dated February 14, 2006 announcing 2005 Year End Reserve Report and Distribution Increase available on our website at www.peyto.com . The complete statement of reserves data and required reporting in compliance with NI 51-101 will be included in Peyto's Annual Information Form to be released in March 2006.

Value Creation

In order to measure investment success, it is necessary to quantify the amount of value created during the year and compare that to the amount of capital invested. We undertake this exercise to ensure the best use of the unitholders' capital on a go forward basis. At Peyto's request and for the benefit of unitholders', the independent engineers have run last year's NPV with this years price forecast to eliminate the change in value attributable to the commodity prices. This approach isolates the value created by the Peyto team from the value created by the change in commodity prices. We were able to create $995 million of Proved and $1,159 million of Proved Plus Probable undiscounted reserve value with $358 million in capital. Relative to our enterprise value, this amount of net value created represents a significant growth rate.

The following table isolates value created by Peyto with the drill bit from the increase in value due to higher commodity prices for both the total proved and proved plus probable cases.

Before Tax Debt Adjusted NPV Reconciliation Table ($million)					
		Total Proved		Proved + Probable Additional	
		Discounted at		Discounted at	
Evaluation	Formula	0%	5%	0%	5%
NPV at Dec 31, 2004 after net debt (Jan 1, 2005 price forecast)	A	$ 2,397	$ 1,288	$ 3,432	$ 1,738
NPV after net debt at Dec 31, 2004 (Jan 1, 2006 price forecast)	B	$ 3,387	$ 1,884	$ 4,857	$ 2,546
NPV at Dec 31, 2005 after net debt (Jan 1, 2006 price forecast)	C	$ 4,075	$ 2,242	$ 5,709	$ 2,922
2005 Funds from operations	D	$ 307	$ 307	$ 307	$ 307
Increase in 2004 NPV due to price forecast	B – A	$ 990	$ 596	$ 1,425	$ 808
NPV created by drill bit in 2005	C - B + D	$ 995	$ 665	$ 1,159	$ 683
Total change in debt adjusted NPV from 2004 to 2005	C – A	$ 1,678	$ 954	$ 2,277	$ 1,184

Performance Measures

There are a number of performance measures that are used in the oil and gas industry in an attempt to evaluate how profitably capital has been invested. These measures, such as capital cost per flowing boe, FD&A, recycle ratio and reserve replacement ratio are incomplete and on their own do not measure success. However, the NPV recycle ratio does measure the value of what was created relative to what was invested. This is because the NPV of an oil and gas asset takes into consideration the reserves, the production forecast, the future royalties and operating costs, future capital and the current commodity price outlook. In 2005 our proven plus probable NPV recycle ratio was 3.2 times. This means for each dollar we invested we were able to create 3.2 new dollars of proven plus probable reserve value.

Our reserves grew faster than our production in 2005. This resulted in an increase of over 10% in reserve life for all of the reserve categories. Our proven plus probable reserve life grew from 17.1 years at the end of 2004 to 18.9 years at the end of 2005. For an energy trust, more money in the “reserve bank” ultimately means more cash distributions for the unitholders.

2005 Performance Ratios	Proved Developed	Total Proved	Proved + Probable
Reserve life index (years)			
Q4 2005 average production – 22,245 boe/d	11.5	13.6	18.9
Finding, development and acquisition costs ($/boe)			
Before change in future development capital	$14.45	$13.33	$11.18
Including change in future development capital	$13.88	$15.32	$15.17
Reserve replacement ratio	3.1	3.3	4.0
Recycle ratio			
Before change in future development capital	3.0	3.2	3.8
Including change in future development capital	3.1	2.8	2.8
NPV Recycle ratio	2.6	2.8	3.2

- Reserve life index can be calculated using various methodologies. We believe the most accurate way to look at the reserve life index is by dividing the proved developed reserves by the actual fourth quarter average production. In our opinion, for comparative purposes the proved developed reserve life will provide the best measure of sustainability.
- FD&A (finding, development and acquisition) costs are used as a measure of capital efficiency and are calculated by dividing the capital costs for the period by the change in the reserves, including revisions, for the same period. Prior to NI 51-101, FD&A costs were calculated excluding future development capital ("FDC"). Both methods of calculating FD&A costs have been provided in order to facilitate comparisons with previous years.
- Reserve replacement ratio is calculated by dividing the yearly change in reserves, including revisions and before production by the actual annual production.

- Recycle ratio is calculated by dividing the field net back per boe, before hedging, by the FD&A costs for the period. In our opinion, it can be a very good measure of investment performance as long as the replacement barrel is of equivalent quality as the produced barrel. Because the recycle ratio is comparing the netback from existing reserves to the cost to find new reserves it may not accurately indicate investment success.
- NPV (net present value) recycle ratio is calculated by dividing the undiscounted NPV of reserves added in the year by the total capital cost for the period. The NPV recycle ratio measures the value of the added reserves relative to their cost.

Quarterly Review

Daily production for the three months averaged 108 mmcf of natural gas and 4,185 barrels of oil and natural gas liquids. Gains in production and commodity prices increased funds from operations from $60.3 million in 2004 to $86.6 million in 2005. Peyto's commodity prices net of hedging increased by 39% averaging $10.55 per mcf of natural gas, and increased by 25% averaging $58.43 per barrel of oil and natural gas liquids. The high heating value of our gas resulted in a 17% premium when converted from gigajoules at the AECO price hub to mcf at the plantgate.

Operating costs averaged $1.95/boe in the fourth quarter of 2005 compared to $1.03/boe for the fourth quarter of 2004. The fixed cost structure associated with these wells combined with a general inflationary effect of over 20% in the service sector caused the increase. In our estimation, any increase in operating costs due to a maturing producing base will be more than offset by a reduction in the royalty rate, resulting in a higher netback per boe. Peyto continues to have the lowest operating costs in the trust sector by a significant margin.

Capital expenditures for the quarter totaled $107.6 million with drilling projects continuing at record levels. Well related activity made up 93% of this capital with drilling and completion costs accounting for $84.2 million while facilities and tie-ins accounted for $16.3 million. Peyto spent a record $3.7 million on land in the quarter in a very competitive market.

Activity Update

To date in 2006, Peyto has drilled and cased 25 gross (20 net) gas wells and brought on-stream 19 gross (18 net) producing zones. We currently have 8 drilling rigs active in our core areas. As expected, production has remained stable at 22,300 boe/d. In the greater Sundance area we have been limited by processing capacity since the beginning of the third quarter of 2005. Drilled and completed reserves are awaiting the March, 2006 completion of our Wildhay Plant. Peyto's fourth 100% owned and operated gas plant will have 20 mmcf/d gas processing capacity and has begun selling gas as we go to press. To the east of Sundance, in the Nose Hill area, Peyto will be constructing a 20 mmcf/d gas plant which is expected to be on-stream by the third quarter of 2006. Both of these gas plants are easily expandable for future production increases.

Marketing

Peyto's marketing strategy is designed to smooth out short term fluctuations in the price of both natural gas and natural gas liquids through future sales. We do this by selling approximately 30% of our gas net of royalties on the daily and monthly spot markets while the other 70% is hedged. Our hedging is meant to be methodical and consistent and to avoid speculation. In general this approach will show hedging losses when short term prices climb and hedging gains when short term prices fall. Over the long run we expect to breakeven on our forward sales. Our hedging approach is based on a forward average price typically made up of fifteen to twenty transactions entered into over a 12 month period. Peyto sells its contracts in either the 7 month summer or the 5 month winter season.

Our natural gas price before hedging averaged $12.60/mcf during the fourth quarter of 2005, an increase of 74% from $7.23/mcf reported for the equivalent period in 2004. Oil and natural gas liquids prices averaged $63.27/bbl up 23% from $51.57/bbl a year earlier. Hedging activity for the fourth quarter of 2005 reduced Peyto's price achieved by $10.93/boe. The fourth quarter hedging loss was $22.4 million, for a year to date total loss of $39.6 million. The following table shows commodity prices and revenue before and after hedging.

Commodity Prices	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2005	2004	**2005**	2004
Natural gas ($/mcf)	**12.60**	7.23	**9.62**	7.19
Hedging – gas ($/mcf)	**(2.05)**	0.35	**(0.84)**	0.19
Natural gas – after hedging ($/mcf)	**10.55**	7.58	**8.78**	7.38
Oil and natural gas liquids($/bbl)	**63.27**	51.57	**59.62**	45.92
Hedging – oil ($/bbl)	**(4.84)**	(4.75)	**(4.14)**	(3.26)
Oil and natural gas liquids – after hedging ($/bbl)	**58.43**	46.82	**55.48**	42.66
Total Hedging ($/boe)	**(10.93)**	0.69	**(4.88)**	0.25

Revenue	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2005**	2004	**2005**	2004
Natural gas	**125,651**	65,126	**374,750**	233,555
Oil and natural gas liquids	**24,359**	20,684	**96,532**	65,237
Hedging gain (loss)	**(22,377)**	1,317	**(39,587)**	1,709
Total revenue	**127,633**	87,127	**431,695**	300,501

As at December 31, 2005, Peyto had committed to the forward sale of 355,100 barrels of crude oil at an average price of $68.19 per barrel and 22.7 million gigajoules (GJ) of natural gas at an average price of $8.64 per GJ. This presold volume for 2006 represents 60% of our current gas production net of royalties and 33% of our current liquids production net of royalties. Based on the historical heating value of Peyto's natural gas, the price per mcf on the forward sale will be $10.11, which is 15% higher than the price Peyto realized in 2005.

Performance Based Compensation

When Peyto converted to a trust in July, 2003, a formal performance based compensation plan was adopted. Performance based compensation was established to compensate employees for per unit market and reserve value growth. The market based component replaced the old stock option plan. It was designed to be less costly, more transparent, more tax efficient for the unitholders and to provide better alignment with unitholders' objectives. The reserve value component was meant to compensate based on per unit growth of the proved producing reserve value discounted at 8%, independent of increases due to commodity prices. A more detailed discussion of our market and reserve value based compensation plan is available on our website.

Total performance based compensation paid in 2005 was $57.8 million (market component - $45 million; reserve value component - $12.8 million). Growth in the share price in the prior two years accounted for 82% of the total market performance based compensation paid in 2005. Total performance based compensation paid by the trust in its first 30 months represents 7% of the total return that unitholders have realized in the market since conversion to a trust.

After the performance based compensation payments, two private placements totaling 1,393,940 trust units were completed to Peyto employees and consultants for proceeds of $34.4 million. Unlike a typical option plan, the employees of Peyto have chosen to re-invest 100% of the after tax proceeds into Peyto trust units at an undiscounted market price. At Peyto, there is a high degree of ownership at all levels; Board, executive and employee. We feel it is through ownership that Peyto's team is best aligned to unitholders.

Sustainable Distributions

As a growth oriented, sustainable trust, our primary objective is to grow our resources from which we generate sustainable distributions for our unitholders. In order for our distributions to be more sustainable and grow, we have to profitably find and develop more reserves. Simply increasing production from our existing reserves will not make us more sustainable. This year we were successful in growing our reserves and improving our sustainability. The results set out herein, continue to prove that our unique model is working. Growth on a per unit basis has allowed us to increase our distributions five times, or by 87% on aggregate, since the conversion to a trust in July 2003. We have now distributed out a total of $271.2 million or $2.855 per unit (adjusted for 2 for 1 split) to our unitholders. Since converting to a trust, we have returned 37% of the unit price at time of conversion, while increasing the reserves per unit by over 102% and the production per unit by 54%.

Effective with the February 2006 production month, cash distributions were increased by 17 percent to $0.14 per unit per month. This latest increase in distribution is a direct result of the growth in reserves and assets of the trust.

On March 2, 2005, Peyto implemented a Distribution Reinvestment Plan ("DRIP"). The DRIP provides a convenient mechanism for unitholders to reinvest their monthly cash distributions in additional trust units. The DRIP permits the purchase of Peyto trust units from treasury at a 5% discount to market price. On November 21, 2005 the DRIP plan was amended to incorporate an Optional Trust Unit Purchase Plan ("OTUPP") component which provides unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP. Peyto will issue trust units from treasury, subject to certain limitations, at the 5% discount to satisfy the requirements of the DRIP/OTUPP, until it discloses otherwise. The DRIP/OTUPP is currently only available to Canadian resident unitholders. Residents of the United States may not participate in the DRIP/OTUPP Plan, as Peyto is not a registrant with the United States Securities and Exchange Commission. Details of the DRIP/OTUPP are available on Peyto's website www.peyto.com.

Outlook

Every year since Peyto started our capital expenditures have grown. We expect that this will again be the case in 2006. This growth in capital expenditures is a direct reflection of the ability of Peyto's technical team to build our own assets. The total amount of capital we ultimately invest in 2006 will be driven by the number and quality of projects we generate. Capital will only be invested if it meets the long term objectives of the trust. The majority of our capital program will involve drilling, completion and tie-in of low risk development gas wells. During the year, Peyto will be constructing two new gas plants to ensure that we can efficiently access the new reserves we are finding. Capital expenditures will continue to be funded with a combination of funds from operations, working capital, equity and bank lines.

We have now completed our seventh year as an energy business. It is amazing how far Peyto has come with our simple strategy of putting value first. Our business has delivered returns and assets which lead the Canadian energy sector. If you understand the value of your own capital and are interested in understanding the value of Peyto, we suggest that you visit the Peyto website at www.peyto.com where you will find a wealth of information designed to educate and inform investors who understand value and real returns.

National Instrument 51-101 Cautionary Statements

The Canadian Securities Administrators have implemented standards of disclosure for reporting issuers engaged in upstream oil and gas activities effective December 31, 2003. The disclosure standards referred to as National Instrument ("NI") 51-101 establish a regime of continuous disclosure for oil and gas companies and include specific reporting requirements.

- Peyto's year-end reserve report summarized herein is compliant with NI 51-101. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate" and hence for years prior to 2003, are compared to "established" reserves which were comprised of proved plus 50 percent of probable reserves.
- The term "boes" may be misleading particularly if used in isolation, a boe conversion ratio of 6 mcf : 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
- It should not be assumed that the discounted net present values represent the fair market value of the reserves.
- The estimate of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.
- The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Don T. Gray
President and Chief Executive Offices
March 8, 2006

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements of Peyto Energy Trust ("Peyto") for the years ended December 31, 2005 and 2004. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

The Trust was created by way of a Plan of Arrangement effective July 1, 2003 which reorganized Peyto Exploration & Development Corp. ("PEDC") from a corporate entity into a trust. Accordingly, the consolidated financial statements were reported on a continuity of interests basis. As such, comparative figures for the periods prior to July 1, 2003 are the financial results of PEDC. This discussion provides management's analysis of Peyto's historical financial and operating results and provides estimates of Peyto's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant. Readers should be aware that historical results are not necessarily indicative of future performance. This MD&A was prepared using information that is current as of March 8, 2006. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com.

Certain information set forth in this Management's Discussion and Analysis, including management's assessment of the Trust's future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond these parties' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Peyto's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Peyto will derive there from. Peyto disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before performance based compensation, non-cash and non-recurring expenses. We believe that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future distributions may vary.

All references are to Canadian dollars unless otherwise indicated. Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl).

Recently, proposed new legislation to restrict foreign ownership was issued in draft form by the Department of Finance and has prompted all trusts, including Peyto, to review their capital structures. To the best of our knowledge, Peyto's foreign ownership level currently stands at approximately 26.3 percent, well below the level that would jeopardize Peyto's status as a mutual fund trust under this proposed legislation. A few trusts have reorganized, or propose to reorganize, their units into a dual class structure with the objective of restricting foreign ownership to less than 50 percent and therefore retaining their status as a mutual fund trust. Peyto is an active supporter of the efforts of the Canadian Association of Income Funds (CAIF) which is attempting to have the Department of Finance reconsider components of the proposed legislation. The Department of Finance has subsequently announced that they are taking more time to consider the proposed legislation. The Trust will continue to monitor these developments and if it is deemed appropriate, propose an amendment to its capital structure.

OVERVIEW

Peyto is a Canadian energy trust involved in the development and production of natural gas in Alberta's deep basin. As at December 31, 2005, we had total proved plus probable reserves of 153.4 million barrels of oil equivalent with a reserve life of 18.9 years as evaluated by our independent petroleum engineers. Our production is weighted as to approximately 83% natural gas and 17% natural gas liquids and oil.

The Peyto model is designed to deliver growth in its assets, production and income, all on a per unit basis. The model is built around three key principles:

- Using our technical expertise to achieve the best return on capital employed, through the development of internally generated drilling projects.
- A low payout ratio designed to efficiently fund our growing inventory of drilling projects.
- Having an asset base which is made up of high quality long life natural gas reserves.

Operating results over the last seven years indicate that we have successfully implemented these principles. Our business model makes Peyto a truly unique energy trust.

ANNUAL FINANCIAL INFORMATION

The following is a summary of selected financial information of the Trust for the periods indicated. Reference should be made to the audited consolidated financial statements of the Trust, which are available at www.sedar.com.

Year Ended December 31 ($000 except per unit amounts)	**2005**	2004	2003
Total revenue (before royalties)	**431,695**	300,501	216,931
Funds from operations	**296,970**	209,106	151,407
Per unit – basic*	**3.01**	2.28	1.705
Per unit – diluted*	**3.01**	2.28	1.705
Earnings (loss)	**161,568**	73,782	48,579
Per unit – basic*	**1.64**	0.805	0.545
Per unit – diluted*	**1.64**	0.805	0.545
Total assets	**944,927**	622,577	416,146
Total long-term debt	**180,000**	180,000	150,000
Cash distributions per unit*	**1.39**	1.02	0.45

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

QUARTERLY FINANCIAL INFORMATION

	2005				2004			
($000 except per unit amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue (net of royalties)	**94,111**	84,912	73,473	72,397	66,024	59,337	53,853	50,197
Funds from operations	**86,607**	77,179	66,548	66,636	60,334	54,211	48,548	46,012
Per unit – basic*	**0.85**	0.78	0.69	0.69	0.65	0.60	0.53	0.51
Per unit – diluted*	**0.85**	0.78	0.69	0.69	0.65	0.60	0.53	0.51
Earnings (loss)	**60,745**	37,702	25,690	37,431	(2,558)	21,650	30,347	24,343
Per unit – basic*	**0.60**	0.38	0.27	0.39	(0.03)	0.24	0.33	0.27
Per unit – diluted*	**0.60**	0.38	0.27	0.39	(0.03)	0.24	0.33	0.27

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

RESULTS OF OPERATIONS

Production

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2005	2004	**2005**	2004
Natural gas (mmcf/d)	**108,356**	97,968	**106,701**	88,842
Oil & natural gas liquids (bbl/d)	**4,185**	4,360	**4,436**	3,882
Barrels of oil equivalent (boe/d)	**22,245**	20,688	**22,219**	18,689

Natural gas production averaged 108.4 mmcf/d in the fourth quarter of 2005, 11 percent higher than the 97.9 mmcf/d reported for the same period in 2004. Oil and natural gas liquids production averaged 4,185 bbl/d, a decrease of 4 percent from 4,360 bbl/d reported in the prior year. Production for the year increased 19 percent from 18,689 boe/d to 22,219 boe/d. The production increases are directly attributable to Peyto's ongoing drilling program.

Commodity Prices

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2005	2004	**2005**	2004
Natural gas ($/mcf)	**12.60**	7.23	**9.62**	7.19
Hedging – gas ($/mcf)	**(2.05)**	0.35	**(0.84)**	0.19
Natural gas – after hedging ($/mcf)	**10.55**	7.58	**8.78**	7.38
Oil and natural gas liquids($/bbl)	**63.27**	51.57	**59.62**	45.92
Hedging – oil ($/bbl)	**(4.84)**	(4.75)	**(4.14)**	(3.26)
Oil and natural gas liquids – after hedging ($/bbl)	**58.43**	46.82	**55.48**	42.66
Total Hedging ($/boe)	**(10.93)**	0.69	**(4.88)**	0.25

Our natural gas price before hedging averaged $12.60/mcf during the fourth quarter of 2005, an increase of 74 percent from $7.23/mcf reported for the equivalent period in 2004. Oil and natural gas liquids prices averaged $63.27/bbl up 23 percent from $51.57/bbl a year earlier. Natural gas prices for the year were up 34 percent at $9.62/mcf while oil and natural gas liquids prices were up 30 percent at $59.62/bbl compared to 2004. Hedging activity for fiscal 2005 decreased Peyto's price achieved by $4.88/boe. Expectations are for commodity prices to remain strong.

Revenue

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2005**	2004	**2005**	2004
Natural gas	**125,651**	65,126	**374,750**	233,555
Oil and natural gas liquids	**24,359**	20,684	**96,532**	65,237
Hedging gain (loss)	**(22,377)**	1,317	**(39,587)**	1,709
Total revenue	**127,633**	87,127	**431,695**	300,501

For the three months ended December 31, 2005, revenue increased 46 percent to $127.6 million from $87.1 million for the same period in 2004. Revenue for the year was up 44 percent as a result of increased production volumes and commodity prices as detailed in the following table:

	Three Months ended Dec. 31				Twelve Months ended Dec. 31			
	2005	2004	Change	**$million**	2005	2004	Change	**$million**
Natural gas								
Volume (mcf/d)	108,356	97,968	10,388		106,701	88,842	17,859	
Volume (mmcf)	9,969	9,013	956	**7.2**	38,946	32,516	6,430	**47.5**
Price ($/mcf)	10.55	7.58	2.97	**29.6**	8.78	7.38	1.40	**54.5**
Oil & NGL								
Volume (bbl/d)	4,185	4,360	(175)		4,436	3,882	554	
Volume (mbbl)	385	401	(16)	**(0.7)**	1,619	1,421	198	**8.4**
Price ($/bbl)	58.43	46.82	11.61	**4.4**	55.48	42.66	12.82	**20.8**
Total revenue ($million)	127.6	87.1	40.5	**40.5**	431.7	300.5	131.2	**131.2**

Royalties

We pay royalties to the owners of the mineral rights with whom we hold leases, including the provincial government of Alberta. Alberta gas crown royalties are invoiced on the Crown's share of production based on a monthly established Alberta Reference Price. The Alberta Reference Price is a monthly weighted average price of gas consumed in Alberta and gas exported from Alberta reduced for transportation and marketing allowances.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2005	2004	**2005**	2004
Royalties, net of ARTC ($000)	**33,522**	21,103	**106,802**	71,089
% of sales	**26**	24	**25**	24
$/boe	**16.38**	11.08	**13.17**	10.39

For the fourth quarter of 2005, royalties averaged $16.38/boe or approximately 26 percent of Peyto's total petroleum and natural gas sales. Year to date royalties were 25 percent of sales in 2005 compared to 24 percent in 2004. The royalty rate expressed as a percentage of sales, will fluctuate from period to period due to the fact that the Alberta Reference Price can differ significantly from the commodity prices obtained by the Trust.

Operating Costs & Transportation

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party gas reduces operating expenses.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2005	2004	**2005**	2004
Operating costs ($000)				
Field expenses	**5,347**	3,984	**17,609**	12,187
Processing and gathering income	**(1,354)**	(2,031)	**(5,063)**	(4,977)
Total operating costs	**3,993**	1,953	**12,546**	7,210
$/boe	**1.95**	1.03	**1.55**	1.05
Transportation	**1,433**	1,456	**5,520**	4,767
$/boe	**0.70**	0.77	**0.68**	0.70

Operating costs were $4.0 million in the fourth quarter of 2005 compared to $2.0 million during the same period a year earlier. Peyto's high level of drilling activity during 2005 resulted in a producing well count increase of over 35%. The fixed cost structure associated with these wells combined with a general inflationary effect of over 20% in the service sector caused the overall cost increase.

On a unit-of-production basis, operating costs averaged $1.95/boe in the fourth quarter of 2005 compared to $1.03/boe for the fourth quarter of 2004. Operating costs for the year averaged $1.55/boe in 2005 compared to $1.05/boe in 2004.

Netbacks

Operating netbacks represent the profit margin associated with the production and sale of petroleum and natural gas. The primary factors that produce Peyto's strong netbacks are a low cost structure and the high heat content of our natural gas that results in higher commodity prices.

($/boe)	Three Months ended Dec. 31 **2005**	2004	Twelve Months ended Dec. 31 **2005**	2004
Sale Price	**62.36**	45.78	**53.23**	43.93
Less:				
Royalties	**16.38**	11.08	**13.17**	10.39
Operating costs	**1.95**	1.03	**1.55**	1.05
Transportation	**0.70**	0.77	**0.68**	0.70
Operating netback	**43.33**	32.90	**37.83**	31.79
General and administrative	**0.05**	0.01	**0.08**	0.12
Interest on long-term debt	**0.91**	1.03	**1.07**	1.01
Capital tax	**0.06**	0.16	**0.06**	0.09
Cash netback	**42.31**	31.69	**36.62**	30.57

General and Administrative Expenses

	Three Months ended Dec. 31 **2005**	2004	Twelve Months ended Dec. 31 **2005**	2004
G&A expenses ($000)	**1,874**	1,451	**6,434**	4,593
Overhead recoveries	**(1,778)**	(1,441)	**(5,754)**	(3,790)
Net G&A expenses	**96**	10	**680**	803
$/boe	**0.05**	0.01	**0.08**	0.12

General and administrative expenses before overhead recoveries increased to $1.9 million in the fourth quarter of 2005, as compared to $1.5 million for the same period in 2004 primarily due to staffing increases required to manage our active drilling program and increasing property base. Net of overhead recoveries associated with our capital expenditures program, general and administrative costs increased to $0.05 per boe in the fourth quarter of 2005, from $0.01 per boe in the fourth quarter of 2004. General and administrative expenses for 2005 averaged $0.08/boe in 2005 compared to $0.12 in 2004.

Interest Expense

	Three Months ended Dec. 31 **2005**	2004	Twelve Months ended Dec. 31 **2005**	2004
Interest expense ($000)	**1,857**	1,964	**8,702**	6,905
$/boe	**0.91**	1.03	**1.07**	1.01

2005 interest expense was $8.7 million or $1.07/boe compared to $6.9 million or $1.01/boe a year earlier. Interest rates continue to be favorable and are not expected to increase substantially in the short-term.

Depletion, Depreciation and Accretion

The 2005 provision for depletion, depreciation and accretion totaled $58.2 million as compared to $40.9 million in 2004. On a unit-of-production basis, depletion, depreciation and accretion costs averaged $7.18/boe as compared to $5.98/boe in 2004. Increases or decreases in the depletion rate on a unit-of-production basis are influenced by the reserves added through Peyto's drilling program. As set out under the section "Critical Accounting Estimates", Peyto adopted the CICA pronouncement with respect to Asset Retirement Obligations, effective January 1, 2004.

Income Taxes

The current provision for future income tax increased to $37.6 million in 2005 from $25.6 million in 2004. Included in the 2005 provision was an amount of $8.8 million recorded in the fourth quarter. Our trust structure is unique in that it was designed to provide for discretion at the operating trust level to distribute taxable income to the Trust. Given the significant level of capital expenditures incurred by Peyto in the fourth quarter, the operating trust had additional resource pool deductions available for use which give rise to temporary differences which increased future income taxes in the fourth quarter. Unitholders benefit as the use of these resource pools increases the tax free return of capital component of the cash distributions.

MARKETING

Commodity Price Risk Management

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Trust enters into these contracts with well established counter-parties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices. During 2005, we recorded a hedging loss of $39.6 million as compared to a hedging gain of $1.7 million in 2004. As set out under the section "Critical Accounting Estimates", we adopted, effective January 1, 2004, the CICA Accounting Guideline 13 with respect to Hedging Relationships. A summary of contracts outstanding in respect of the hedging activities are as follows:

Crude Oil Period Hedged	Type	Daily Volume	Price (CAD)
January 1 to March 31, 2006	Fixed price	300 bbl	$53.85/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$54.58/bbl
January 1 to March 31, 2006	Fixed price	300 bbl	$57.65/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$58.90/bbl
January 1 to March 31, 2006	Fixed price	200 bbl	$65.21/bbl
January 1 to March 31, 2006	Fixed price	100 bbl	$69.40/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$64.75/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$64.62/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$68.64/bbl
April 1 to June 30, 2006	Fixed price	300 bbl	$76.00/bbl
April 1 to June 30, 2006	Fixed price	200 bbl	$81.00/bbl
July 1 to September 30, 2006	Fixed price	200 bbl	$70.00/bbl
July 1 to September 30, 2006	Fixed price	200 bbl	$72.15/bbl
July 1 to September 30, 2006	Fixed price	300 bbl	$75.40/bbl
July 1 to September 30, 2006	Fixed price	200 bbl	$80.10/bbl
October 1 to December 31, 2006	Fixed price	200 bbl	$69.40/bbl
October 1 to December 31, 2006	Fixed price	200 bbl	$71.10/bbl
October 1 to December 31, 2006	Fixed price	200 bbl	$79.00/bbl

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.40/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.50/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.60/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.70/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.80/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$7.91/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.01/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.15/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.22/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.32/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.50/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.72/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$8.55/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$9.00/GJ
Nov. 1, 2005 to March 31, 2006	Fixed price	5,000 GJ	$9.75/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.10/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.20/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.30/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.35/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.45/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.61/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$7.75/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$9.30/GJ
April 1 to October 31, 2006	Fixed price	5,000 GJ	$10.60/GJ

April 1 to October 31, 2006	Fixed price	5,000 GJ	$10.60/GJ
April 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.27/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$8.71/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.00/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.05/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$10.06/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$10.28/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$11.40/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$11.60/GJ

Commodity Price Sensitivity

Our low operating costs, low distribution ratio and long reserve life reduce our sensitivity to changes in commodity prices.

Currency Risk Management

The Trust is exposed to fluctuations in the Canadian/US dollar exchange ratio since our natural gas and oil sales are effectively priced in US dollars and converted to Canadian dollars. Currently we have not entered into any agreements to manage this specific risk.

Interest Rate Risk Management

The Trust is exposed to interest rate risk in relation to interest expense on its revolving demand facility. Currently we have not entered into any agreements to manage this risk. At December 31, 2005, the increase or decrease in earnings for each 100 bps change in interest rate paid on the outstanding revolving demand loan amounts to approximately $2.2 million per annum.

LIQUIDITY AND CAPITAL RESOURCES

Funds from Operations

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2005**	2004	**2005**	2004
Net earnings	**60,745**	(2,558)	**161,568**	73,782
Items not requiring cash:				
Non-cash provision for (recovery of) performance based compensation	**(57,459)**	(15,966)	**(18,271)**	15,945
Future income tax expense	**8,832**	15,140	**37,618**	25,558
Depletion, depreciation & accretion	**16,642**	10,777	**58,208**	40,880
Non-recurring items:				
Market and reserve value performance based compensation	**57,847**	52,941	**57,847**	52,941
Funds from operations	**86,607**	60,334	**296,970**	209,106

For the quarter ended December 31, 2005, funds from operations totaled $86.6 million or $0.85 per unit, representing a 31 percent increase from the $60.3 million, or $0.65 per unit during the same period in 2004. For fiscal 2005 funds from operations totaled $297.0 million or $3.01 per unit compared to $209.1 million or $2.28 per unit in 2004. Peyto's policy is to distribute approximately 50% of funds from operations to unitholders while retaining the balance to fund its growth oriented capital expenditures program. Our earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond our control. Current volatility in commodity prices creates uncertainty as to our funds from operations and capital expenditure budget. Accordingly, we assess results throughout the year and revise our operational plans as necessary to reflect the most current information.

Our revenues will be impacted by drilling success and production volumes as well as external factors such as the market prices for natural gas and crude oil and the exchange rate of the Canadian dollar relative to the US dollar.

Bank Debt

We have an extendible revolving term credit facility with a syndicate of financial institutions in the amount of $350 million including a $330 million revolving facility and a $20 million operating facility. Available borrowings are limited by a borrowing base, which is based on the value of petroleum and natural gas assets as determined by the lenders. The loan is reviewed annually and may be extended at the option of the lender for an additional 364 day period. If not extended, the revolving facility will automatically convert to a one year and one day non-revolving term loan. The loan has therefore been classified as long-term on the balance sheet. The average borrowing rate for 2005 was 4.0% (2004 – 3.7%).

At December 31, 2005, $180 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At December 31, 2005, we had a working capital deficit of $116.5 million.

We believe that funds generated from our operations, together with borrowings under our credit facility and proceeds from equity issued will be sufficient to finance our current operations and planned capital expenditure program. Every year since Peyto started our capital expenditures have grown. We expect that this will again be the case in 2006. The total amount of capital we ultimately invest in 2006 will be driven by the number and quality of projects we generate. Capital will only be invested if it meets the long term objectives of the trust. The majority of our capital program will involve drilling, completion and tie-in of low risk development gas wells. During the year, Peyto will be constructing two new gas plants to ensure that we can efficiently access the new reserves we are finding. Peyto has the flexibility to match planned capital expenditures to actual cash flow.

Capital

Peyto implemented a Distribution Reinvestment Plan ("DRIP") effective with the March 2005 distribution whereby eligible unitholders may elect to reinvest their monthly cash distributions in additional trust units at a 5% discount to market price. On November 21, 2005 the DRIP plan was amended to incorporate an Optional Trust Unit Purchase Plan ("OTUPP") which provides unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP.

On December 31, 2005 the Trust completed a private placement of 1,081,570 trust units to employees and consultants for net proceeds of $27,450,247. These trust units were issued on January 12, 2006. On January 13, 2006 35,284 trust units (30,004 pursuant to the DRIP and 5,280 pursuant to the OTUPP) were issued for net proceeds of $882,100.

At December 31, 2005 units to be issued were 1,116,854 on account of the December 31, 2005 private placement, and the December, 2005 Distribution Reinvestment Plan/Optional Trust Unit Purchase Plan. On January 13, 2006, subsequent to the issuance of these units, 103,450,701 trust units were outstanding (December 31, 2005 – 102,333,847).

Authorized: Unlimited number of voting trust units
Issued and Outstanding:

Trust Units (no par value)	Number of Shares/Units	Amount $
Balance, December 31, 2003	45,395,122	49,227,530
Trust units issued by private placement	330,150	9,013,095
Trust units issued	2,000,000	85,300,000
Trust unit issue costs	-	(4,587,599)
Balance, December 31, 2004	47,725,272	138,953,026
Trust units issued by private placement	670,000	31,586,375
Trust unit issue costs	-	(103,010)
Trust units issued pursuant to DRIP	28,645	1,356,148
Trust units issued pursuant to 2 for 1 split	48,423,917	-
Trust units issued by public offering	5,000,000	152,750,000
Trust unit issue costs	-	(8,054,775)
Trust units issued pursuant to DRIP	279,561	7,448,146
Trust units issued pursuant to OTUPP	206,452	4,800,000
Balance, December 31, 2005	**102,333,847**	**328,735,910**

Performance Based Compensation

The Trust awards performance based compensation to employees and key consultants annually. The performance based compensation is comprised of market and reserve value based components.

The reserve value based component is 3% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and distributions, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%.

($ million except unit values)	2005	2004	Change
Net present value of proved producing reserves @ 8% based on constant Paddock Lindstrom 2005 price forecast	2,121.0	1,691.0	
Net debt before performance based compensation	(257.4)	(223.0)	
2005 distributions	-	(136.6)	
Net value	1,863.6	1,331.4	532.2
Equity adjustment factor*			80%
Equity adjusted increase in value			427.1
2005 reserve value based compensation @ 3%			$12.8

*Equity adjustment factor is calculated as the percent increase in value per unit divided by the total percent increase in value

Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 7% of the total number of trust units outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. Compensation is calculated as the number of vested rights multiplied by the total of the market appreciation (over the price at the date of grant) and associated distributions of a trust unit for that period. A tax factor of 1.333 is then applied to determine the amount to be paid. The 2005 market based component was based on 2.0 million vested rights at an average grant price of $10.82, average cumulative distributions of $4.36 and the five day weighted average closing price of $25.38 (2004 – 2.0 million rights, average grant price of $8.41, average cumulative distributions of $1.365 per unit and five day weighted average closing price of $23.77, all 2004 comparatives adjusted to reflect the May 31, 2005 2 for 1 unit split). In the fourth quarter of 2005, there was a recovery of the previously recorded provision for future performance based compensation due to a reduction of trust unit market price.

The total amount expensed under these plans was as follows:

	2005 $	2004 $
Market based compensation	**45,045,054**	44,607,873
Reserve value based compensation	**12,802,000**	8,333,000
Total	**57,847,054**	52,940,873

Compensation costs as at December 31, 2005 related to 2.6 million non-vested rights with an average grant price of $20.31 was $21.7 million of which a non-cash provision for future compensation expense of $6.1 million was recorded at December 31, 2004 and an additional $4.0 million was recorded in 2005.

Capital Expenditures

Net capital expenditures for the fourth quarter of 2005 totaled $107.6 million. Exploration and development related activity represented $91.3 million or 85% of the total, while expenditures on facilities, gathering systems and equipment totaled $16.3 million or 15% of the total. The following table summarizes capital expenditures for the year.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2005**	2004	**2005**	2004
Land	**3,657**	772	**12,324**	3,975
Seismic	**3,309**	3,314	**11,559**	5,768
Drilling – Exploratory & Development	**84,189**	61,007	**274,360**	167,742
Production Equipment, Facilities & Pipelines	**16,308**	11,799	**59,810**	49,898
Acquisitions & Dispositions	**-**	52	**-**	3,307
Office Equipment	**184**	9	**401**	84
Total Capital Expenditures	**107,647**	76,953	**358,454**	230,774

Cash Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2005	2004	**2005**	2004
Funds from operations ($000)	**86,607**	60,334	**296,970**	209,106
Distributions ($000)	**36,773**	26,443	**136,648**	93,660
Distributions per unit ($)*	**0.36**	0.285	**1.39**	1.02
Payout ratio (%)	**42**	44	**46**	45

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

Peyto's strategy is to distribute approximately 50 percent of funds from operations to our unitholders on a monthly basis with the balance being withheld to fund capital expenditures. Management is prepared to adjust the payout levels to balance desired distributions with our requirement to maintain an appropriate capital structure. For Canadian income tax purposes distributions made are considered a combination of income and return of capital. The portion that is return of capital reduces the adjusted cost base of the units.

Contractual Obligations

The Trust is committed to payments under operating leases for office space as follows:

	$
2006	953,484
2007	953,484
2008	1,096,641
2009	1,096,641
2010	1,096,641
2011	1,096,641
	6,293,532

GUARANTEES/OFF-BALANCE SHEET ARRANGEMENTS

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts as discussed further in the Hedging section.

INCOME TAXES

The following sets out a general discussion of the Canadian and US tax consequences of holding Peyto units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Unitholders or potential Unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Taxpayers

The Trust qualifies as a mutual fund trust under the *Income Tax Act* (Canada) and, accordingly, Trust units are qualified investments for RRSPs, RRIFs, RESPs and DPSPs. Each year, the Trust is required to file an income tax return and any taxable income of the Trust is allocated to unitholders.

Unitholders are required to include in computing income their pro-rata share of any taxable income earned by the Trust in that year. An investor's adjusted cost base (ACB) in a trust unit equals the purchase price of the unit less any non-taxable cash distributions received from the date of acquisition. To the extent the unitholders' ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholders' ACB will be brought to nil.

During 2005, the Trust paid distributions to the unitholders in the amount of $136.7 million (2004 - $93.7 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit*
January 2005	January 31, 2005	February 15, 2005	$0.095
February 2005	February 28, 2005	March 13, 2005	$0.11
March 2005	March 31, 2005	April 15, 2005	$0.11
April 2005	April 29, 2005	May 15, 2005	$0.11
May 2005	May 31, 2005	June 15, 2005	$0.12
June 2005	June 30, 2005	July 15, 2005	$0.12
July 2005	July 29, 2005	August 15, 2005	$0.12
August 2005	August 31, 2005	September 15, 2005	$0.12
September 2005	September 30, 2005	October 14, 2005	$0.12
October 2005	October 31, 2005	November 15, 2005	$0.12
November 2005	November 30, 2005	December 15, 2005	$0.12
December 2005	December 28, 2005	January 13, 2006	$0.12
			$1.385

*Note: restated for 2 for 1 split of trust units completed May 31, 2005.

US Taxpayers

US unitholders who receive cash distributions are subject to a 15 percent Canadian withholding tax, applied to the taxable portion of the distributions as computed under Canadian tax law. US taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

The taxable portion of the cash distributions, if any, is determined by the Trust in relation to its current and accumulated earnings and profit using US tax principles. The taxable portion so determined, is considered to be a dividend for US tax purposes.

The non-taxable portion of the cash distributions is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as a gain.

US unitholders are advised to seek legal or tax advice from their professional advisors.

RISK MANAGEMENT

Investors who purchase our units are participating in the net funds from operations from a portfolio of western Canadian crude oil and natural gas producing properties. As such, the funds from operations paid to investors and the value of the units are subject to numerous risks inherent in the oil and natural gas industry.

Our expected funds from operations depends largely on the volume of petroleum and natural gas production and the price received for such production, along with the associated costs. The price we receive for our oil depends on a number of factors, including West Texas Intermediate oil prices, Canadian/US currency exchange rates, quality differentials and Edmonton par oil prices. The price we receive for our natural gas production is primarily dependent on current Alberta market prices. Peyto’s marketing strategy is designed to smooth out short term fluctuations in the price of both natural gas and natural gas liquids through future sales. It is meant to be methodical and consistent and to avoid speculation.

Although our focus is on internally generated drilling programs, any acquisition of oil and natural gas assets depends on our assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of the units. We employ experienced staff on our team and perform appropriate levels of due diligence on our analysis of acquisition targets, including a detailed examination of reserve reports; if appropriate, re-engineering of reserves for a large portion of the properties to ensure the results are consistent; site examinations of facilities for environmental liabilities; detailed examination of balance sheet accounts; review of contracts; review of prior year tax returns and modeling of the acquisition to attempt to ensure accretive results to the unitholders.

Inherent in development of the existing oil and gas reserves are the risks, among others, of drilling dry holes, encountering production or drilling difficulties or experiencing high decline rates in producing wells. To minimize these risks, we employ experienced staff to evaluate and operate wells and utilize appropriate technology in our operations. In addition, we use prudent work practices and procedures, safety programs and risk management principles, including insurance coverage against certain potential losses.

The value of our Trust units is based on among other things, the underlying value of the oil and natural gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and gas prices increase the risk of write-downs on our oil and gas property investments. In order to mitigate this risk, our proven and probable oil and gas reserves are evaluated each year by a firm of independent reservoir engineers. The reserves committee of the Board of Directors reviews and approves the reserve report.

Our access to markets may be restricted at times by pipeline or processing capacity. We minimize these risks by controlling as much of our processing and transportation activities as possible and ensuring transportation and processing contracts are in place with reliable cost efficient counter-parties.

The petroleum and natural gas industry is subject to extensive controls, regulatory policies and income and resource taxes imposed by various levels of government. These regulations, controls and taxation policies are amended from time to time. We have no control over the level of government intervention or taxation in the petroleum and natural gas industry. However, we operate in such a manner to ensure, to the best of our knowledge that we are in compliance with all applicable regulations and are able to respond to changes as they occur.

The petroleum and natural gas industry is subject to both environmental regulations and an increased environmental awareness. We have reviewed our environmental risks and are, to the best of our knowledge, in compliance with the appropriate environmental legislation and have determined that there is no current material impact on our operations.

We are subject to financial market risk. In order to maintain substantial rates of growth, we must continue reinvesting in, drilling for or acquiring petroleum and natural gas. Our capital expenditure program is funded primarily through funds from operations, debt and equity.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the Chief Executive Officer ("CEO") and Vice President, Finance ("VPF"), on a timely basis so that appropriate decisions can be made regarding public disclosure.

As of the end of the period covered by this report, Peyto's management evaluated the effectiveness of the design and operation of its disclosure controls and procedures, under the supervision of, and with the participation of the CEO and VPF. Based on this evaluation, the CEO and VPF have concluded that Peyto's disclosure controls and procedures, as defined in Multilateral Instrument 52-109, Certification of Disclosure in Issuers Annual and Interim Filings are effective to ensure that material information relating to Peyto is made known to management on a timely basis and is included in this report.

CRITICAL ACCOUNTING ESTIMATES

Reserve Estimates

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent to the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is an analytical process of estimating underground accumulations of oil and natural gas that can be difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future royalties and operating costs, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Trust's oil and natural gas properties and the rate of depletion of the oil and natural gas properties as well as the calculation of the reserve value based compensation. Actual production, revenues and expenditures with respect to the Trust's reserves will likely vary from estimates, and such variances may be material.

The Trust's estimated quantities of proved and probable reserves at December 31, 2005 were audited by independent petroleum engineers Paddock Lindstrom & Associates Ltd. Paddock has been evaluating reserves in this area and for Peyto for 7 consecutive years.

Depletion and Depreciation Estimate

We follow the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

All costs of exploring for and developing petroleum and natural gas reserves, together with the costs of production equipment, are depleted and depreciated on the unit-of-production method based on estimated gross proven reserves. Petroleum and natural gas reserves and production are converted into equivalent units based upon estimated relative energy content (6 mcf to 1 barrel of oil).

Costs of acquiring unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The ceiling test is based on estimates of proved reserves, production rates, estimated future petroleum and natural gas prices and costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

Asset Retirement Obligation

The asset retirement obligation is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonment and reclamation discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time and for revisions to the estimated future cash flows, with the accretion charged to earnings. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Future Market Performance Based Compensation

The provision for future market based compensation is estimated based on current market conditions, distribution history and on the assumption that all outstanding rights will be paid out according to the vesting schedule. The conditions at the time of vesting could vary significantly from the current conditions and may have a material effect on the calculation.

Reserve Value Performance Based Compensation

The reserve value based compensation is calculated using the year end independent reserves evaluation which was completed in January 2006. A quarterly provision for the reserve value based compensation is calculated using estimated proved producing reserve additions adjusted for changes in debt, equity and distributions. Actual proved producing reserves additions and forecasted commodity prices could vary significantly from those estimated and may have a material effect on the calculation.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

RECENT ACCOUNTING PRONOUNCEMENTS

Comprehensive Income, Financial Instruments and Hedges

The CICA issued new standards in early 2005 for Comprehensive Income (CICA 1530), Financial Instruments (CICA 3855) and Hedges (CICA 3865) which will be effective for the reporting year end 2007. The new standards will bring Canadian rules in line with current rules in the US. The standards will introduce the concept of "Comprehensive Income" to Canadian GAAP and will require that an enterprise (a) classify items of comprehensive income by their nature in a financial statement and (b) display the accumulated balance of comprehensive income separately from retained earnings and additional paid-in capital in the equity section of the statement of financial position. Derivative contracts will be carried on the balance sheet at their mark-to-market value, with the change in value flowing to either net income or comprehensive income. Gains and losses on instruments that are identified as hedges will flow initially to comprehensive income and be brought into net income at the time the underlying hedged item is settled. It is expected that this standard will be effective for the Trust's 2007 reporting. Any instruments that do not qualify for hedge accounting will be marked-to-market with the adjustment (tax effected) flowing through the income statement.

ADDITIONAL INFORMATION

Additional information relating to Peyto Energy Trust can be found on SEDAR at www.sedar.com and www.peyto.com.

Quarterly Information

	2005				2004
	Q4	Q3	Q2	Q1	Q4
Operations					
Production					
Natural gas (mcf/d)	**108,356**	108,460	106,866	103,043	97,968
Oil & NGLs (bbl/d)	**4,185**	4,569	4,653	4,337	4,360
Barrels of oil equivalent (boe/d @ 6:1)	**22,245**	22,646	22,464	21,511	20,688
Average product prices					
Natural gas ($/mcf)	**10.55**	8.67	8.00	7.81	7.58
Oil & natural gas liquids ($/bbl)	**58.43**	57.22	51.03	55.52	46.82
Average operating expenses ($/boe)	**1.95**	1.70	1.30	1.22	1.03
Average transportation costs ($/boe)	**0.70**	0.66	0.68	0.68	0.77
Field netback ($/boe)	**43.33**	38.39	33.97	35.50	32.90
General & administrative expense ($/boe)	**0.05**	0.13	0.10	0.06	0.01
Interest expense ($/boe)	**0.91**	1.16	1.25	0.97	1.03
Financial ($000 except per unit)					
Revenue	**127,633**	110,566	99,427	94,069	87,127
Royalties (net of ARTC)	**33,522**	25,654	25,954	21,672	21,103
Funds from operations	**86,607**	77,179	66,548	66,636	60,334
Funds from operations per unit*	**0.85**	0.78	0.69	0.69	0.65
Cash distributions	**36,773**	35,505	33,898	30,472	26,443
Cash distributions per unit*	**0.36**	0.36	0.35	0.315	0.285
Percentage of funds from operations distributed	**42%**	46%	51%	46%	44%
Earnings	**60,745**	37,702	25,690	37,431	(2,558)
Earnings per diluted unit*	**0.60**	0.38	0.27	0.39	(0.03)
Capital expenditures	**107,647**	93,001	58,730	99,074	76,953
Weighted average trust units outstanding*	**102,148,411**	98,584,597	96,848,988	96,664,210	92,494,022

*Note: prior periods restated for 2 for 1 split of trust units completed May 31, 2005.

Auditors' Report

To the Unitholders of
Peyto Energy Trust:

We have audited the consolidated balance sheet of **Peyto Energy Trust** as at December 31, 2005 and 2004 and the consolidated statements of earnings and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Calgary, Alberta
February 17, 2006

Chartered Accountants

Peyto Energy Trust

CONSOLIDATED BALANCE SHEETS

	December 31, 2005 $	December 31, 2004 $
Assets		
Current		
Accounts receivable	**82,793,463**	58,992,005
Due from private placements *(Note 6)*	**27,450,247**	27,080,066
Prepaid expenses and deposits	**1,795,540**	5,262,778
	112,039,250	91,334,849
Property, plant and equipment *(Note 3)*	**832,887,287**	531,241,786
	944,926,537	622,576,635
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	**208,284,019**	124,753,199
Capital taxes payable	**110,412**	483,081
Cash distributions payable	**11,529,973**	9,067,811
Provision for future performance based compensation *(Note 10)*	**8,748,198**	22,298,937
	228,672,602	156,603,028
Long-term debt *(Note 4)*	**180,000,000**	180,000,000
Provision for future performance based compensation *(Note 10)*	**1,400,970**	6,121,097
Asset retirement obligations *(Note 5)*	**4,729,098**	3,328,834
Future income taxes *(Note 11)*	**108,292,966**	70,675,002
	294,423,034	260,124,933
Unitholders' equity		
Unitholders' capital *(Note 6)*	**328,735,910**	138,953,026
Units to be issued *(Note 6)*	**28,332,345**	27,052,850
Accumulated earnings	**335,925,837**	174,358,093
Accumulated cash distributions *(Note 7)*	**(271,163,191)**	(134,515,295)
	421,830,901	205,848,674
	944,926,537	622,576,635

See accompanying notes

On behalf of the Board:

"Michael MacBean"
Director

"Donald T. Gray"
Director

Peyto Energy Trust

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

For the years ended December 31,

	2005	2004
	$	$
Revenue		
Petroleum and natural gas sales, net	**324,892,613**	229,412,031
Expenses		
Operating *(Note 8)*	**12,546,248**	7,210,155
Transportation	**5,520,140**	4,766,755
General and administrative*(Note 9)*	**679,529**	803,458
Performance based compensation *(Note 10)*	**57,847,054**	52,940,873
Future performance based compensation provision *(Note10)*	**(18,270,866)**	15,944,936
Interest on long term debt	**8,701,501**	6,904,809
Depletion, depreciation and accretion *(Note 3 and 5)*	**58,208,298**	40,879,937
	125,231,904	129,450,923
Earnings before taxes	**199,660,709**	99,961,108
Taxes		
Future income tax expense *(Note 11)*	**37,617,965**	25,558,297
Capital tax expense	**475,000**	621,177
	38,092,965	26,179,474
Net earnings for the year	**161,567,744**	73,781,634
Accumulated earnings, beginning of year	**174,358,093**	100,576,459
Accumulated earnings, end of year	**335,925,837**	174,358,093
Earnings per unit *(Note 6)*		
Basic	**1.64**	0.805
Diluted	**1.64**	0.805

See accompanying notes

Peyto Energy Trust

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,

	2005	2004
	$	$
Cash provided by (used in)		
Operating Activities		
Net earnings for the year	**161,567,744**	73,781,634
Items not requiring cash:		
Non-cash provision for (recovery of) performance based compensation	**(18,270,866)**	15,944,936
Future income tax expense	**37,617,965**	25,558,297
Depletion, depreciation and accretion	**58,208,298**	40,879,937
Change in non-cash working capital related to operating activities *(Note 13)*	**35,776,839**	5,029,631
	274,899,980	161,194,435
Financing Activities		
Issue of trust units, net of costs	**191,062,379**	107,765,251
Distribution payments	**(136,647,896)**	(93,659,685)
Increase in bank debt	**-**	30,000,000
Change in non-cash working capital related to financing activities *(Note 13)*	**2,091,981**	(15,808,428)
	56,506,464	28,297,138
Investing Activities		
Additions to property, plant and equipment	**(358,453,535)**	(230,773,505)
Change in non-cash working capital related to investing activities *(Note 13)*	**27,047,091**	20,690,714
	(331,406,444)	(210,082,791)
Net increase (decrease) in cash	**-**	(20,591,218)
Cash, beginning of year	**-**	20,591,218
Cash, end of year	**-**	-

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2005 and 2004

1. NATURE OF OPERATIONS

Peyto Energy Trust (the "Trust") is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The Trust indirectly owns all of the securities of Peyto Exploration & Development Corp. ("Peyto") which entitles the Trust to receive all cash flow available for distribution from the business of Peyto after debt service payments, maintenance capital expenditures and other cash requirements. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust and are entitled to one vote for each Trust unit held at unitholder meetings. The Trust units trade on the TSX under the symbol "PEY.UN". The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in western Canada.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies summarized below.

These financial statements include the accounts of Peyto Energy Trust and its wholly owned subsidiaries, Peyto Exploration & Development Corp. and Peyto Operating Trust.

Joint operations

The Trust conducts a portion of its petroleum and natural gas exploration, development and production activities jointly with others and, accordingly, these consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Property, plant and equipment

The Trust follows the full cost method of accounting for its petroleum and natural gas properties. All costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities. All other general and administrative costs are expensed as incurred.

The Trust evaluates its petroleum and natural gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves plus the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves plus the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using a risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

All costs of acquisition, exploration and development of petroleum and natural gas reserves (net of salvage value) and estimated costs of future development of proved undeveloped reserves are depleted and depreciated using the unit of production method based on estimated gross proved reserves as determined by independent engineers. For purposes of the depletion and depreciation calculation, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Costs of unproved properties are initially excluded from petroleum and natural gas properties for the purpose of calculating depletion. When proved reserves are assigned to the property or it is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Depreciation of gas plants and related facilities is calculated on a straight-line basis over a 20-year term. Office furniture and equipment are depreciated over their estimated useful lives at declining balance rates between 20% and 30%.

Asset retirement obligations

The Trust records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

Hedging

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. The Trust does not enter into derivative financial instruments for trading or speculative purposes. The derivative financial instruments are initiated within the guidelines of the Trust's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Trust enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

If hedge accounting were not followed, these derivative contracts would be treated as freestanding derivative financial instruments. Any resulting financial asset or liability would be recognized in the balance sheet and measured at fair value, with changes in fair value recognized currently in income.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2005 and 2004

Revenue recognition

Petroleum and natural gas sales are recognized as revenue when title passes to purchasers, normally at pipeline delivery point for natural gas and at the wellhead for crude oil.

Measurement uncertainty

The amount recorded for depletion and depreciation of property, plant and equipment, the asset retirement obligation and the ceiling test calculation are based on estimates of gross proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

Future income taxes

The Trust follows the liability method of tax allocation. Under this method future income tax assets and liabilities of its subsidiaries are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. As the Trust distributes all of its taxable income to unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for future income taxes in the Trust has been made.

3. PROPERTY, PLANT AND EQUIPMENT

	2005	2004
	$	$
Property, plant and equipment	**976,005,103**	616,422,327
Accumulated depletion and depreciation	**(143,117,816)**	(85,180,541)
	832,887,287	531,241,786

At December 31, 2005 costs of $33,617,224 (December 31, 2004 - $28,663,020) related to undeveloped land have been excluded from the depletion and depreciation calculation.

The Trust performed a ceiling test calculation at December 31, 2005 resulting in the undiscounted cash flows from proved reserves plus the lower of cost and market of unproved properties exceeding the carrying value of petroleum and natural gas assets. The impairment test was calculated at December 31, 2005 using the following independent engineering consultant's forecasted prices:

	2006	**2007**	**2008**	**2009**	**2010**	**Thereafter (2)**
Edmonton Ref Price ($CDN/bbl)(1)	69.57	66.61	63.64	60.68	57.72	+2%
AECO ($CDN/mmbtu)	10.54	9.52	8.32	7.71	7.10	+2%

(1) Future prices incorporated a $0.85 US/CDN exchange rate.
(2) Percentage change of 2.0% represents the change in future prices each year after 2010 to the end of the reserve life.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2005 and 2004

4. LONG-TERM DEBT

The Trust has a syndicated $350 million extendible revolving credit facility. The facility is made up of a $20 million working capital sub-tranche and a $330 million production line. The facilities are available on a revolving basis for a period of at least 364 days and upon the term out date may be extended for a further 364 day period at the request of the Trust, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a one year term, at the end of which time the facility would be due and payable. Outstanding amounts on this facility bear interest at rates determined by the Trust's debt to cash flow ratio that range from prime to prime plus 0.75% for debt to cash flow ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank. The average borrowing rate for 2005 was 4.0% (2004 – 3.7%).

5. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligations are 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 $4.7 million as at December 31, 2005 based on a total future liability of $19.8 million. These payments are expected to be made over the next 50 years. The Trust's credit adjusted risk free rate of 7% and an inflation rate of 2% were used to calculate the present value of the asset retirement obligations.

The following table reconciles the change in asset retirement obligations:

	2005 **$**	2004 $
Carrying amount, beginning of year	**3,328,834**	2,279,411
Increase in liabilities during the period	**1,129,241**	860,453
Settlement of liabilities during the period	**-**	-
Accretion expense	**271,023**	188,970
Carrying amount, end of year	**4,729,098**	3,328,834

6. UNITHOLDERS' CAPITAL

Authorized: Unlimited number of voting trust units

Issued and Outstanding

Trust Units (no par value)	Number of Shares/Units	Amount $
Balance, December 31, 2003	45,395,122	49,227,530
Trust units issued by private placement	330,150	9,013,095
Trust units issued by public offering	2,000,000	85,300,000
Trust unit issue costs	-	(4,587,599)
Balance, December 31, 2004	47,725,272	138,953,026
Trust units issued by private placement	670,000	31,586,375
Trust unit issue costs	-	(103,010)
Trust units issued pursuant to Distribution Reinvestment Plan (DRIP)	28,645	1,356,148
Trust units issued pursuant to 2 for 1 split	48,423,917	-
Trust units issued by public offering	5,000,000	152,750,000
Trust unit issue costs	-	(8,054,775)
Trust units issued pursuant to DRIP	279,561	7,448,146
Trust units issued pursuant to Optional Trust Unit Purchase Plan (OTUPP)	206,452	4,800,000
Balance, December 31, 2005	102,333,847	328,735,910

On March 2, 2005, Peyto implemented a Distribution Reinvestment Plan ("DRIP"). On November 21, 2005 the DRIP plan was amended to incorporate an Optional Trust Unit Purchase Plan ("OTUPP") which provides unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury subject to certain limitations, using the same pricing as the DRIP.

Units to be Issued

On December 31, 2005 the Trust completed a private placement of 1,081,570 trust units to employees and consultants for net proceeds of $27,450,247. These trust units were issued on January 12, 2006. On January 13, 2006 35,284 trust units (30,004 pursuant to the DRIP and 5,280 pursuant to the OTUPP) were issued for net proceeds of $882,100. On December 31, 2004 the Trust completed a private placement of 582,500 trust units to employees and consultants for net proceeds of $27,052,850. The trust units were issued on January 4, 2005.

Per Unit Amounts

Earnings per unit have been calculated based upon the weighted average number of units outstanding during the year of 98,576,640 (2004 –91,711,034). There are no dilutive instruments outstanding.

*Note: prior periods have been restated for 2 for 1 split of trust units completed May 31, 2005.

Redemption of Units

The Trust Units are redeemable at any time on demand by the holders thereof. Upon receipt of proper notice to redeem Trust Units by the Trust, the holder thereof shall only be entitled to receive a price per Trust Unit equal to the lesser of:

(a) 90% of the market price of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to the Trust for redemption; and

(b) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

The total amount payable by the Trust in respect of the redemption of all Trust Units tendered for redemption shall not exceed $100,000 in the same calendar month, however such limitation may be waived by the Trust.

7. ACCUMULATED CASH DISTRIBUTIONS

Peyto's strategy is to distribute approximately 50 percent of funds from operations to our unitholders on a monthly basis with the balance being withheld to fund capital expenditures. Management is prepared to adjust the payout levels to balance desired distributions with our requirement to maintain an appropriate capital structure. During the year, the Trust paid distributions to the unitholders in the aggregate amount of $136.7 million (2004 - $93.7 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit*
January 2005	January 31, 2005	February 15, 2005	$0.095
February 2005	February 28, 2005	March 13, 2005	$0.11
March 2005	March 31, 2005	April 15, 2005	$0.11
April 2005	April 29, 2005	May 15, 2005	$0.11
May 2005	May 31, 2005	June 15, 2005	$0.12
June 2005	June 30, 2005	July 15, 2005	$0.12
July 2005	July 29, 2005	August 15, 2005	$0.12
August 2005	August 31, 2005	September 15, 2005	$0.12
September 2005	September 30, 2005	October 14, 2005	$0.12
October 2005	October 31, 2005	November 15, 2005	$0.12
November 2005	November 30, 2005	December 15, 2005	$0.12
December 2005	December 28, 2005	January 13, 2006	$0.12

*Note: prior periods have been restated for 2 for 1 split of trust units completed May 31, 2005.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2005 and 2004

8. OPERATING EXPENSES

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party natural gas reduces operating expenses.

	2005 **$**	2004 $
Field expenses	**17,609,057**	12,187,102
Processing and gathering income	**(5,062,809)**	(4,976,947)
Total operating costs	**12,546,248**	7,210,155

9. GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses are reduced by operating and capital overhead recoveries from operated properties.

	2005 **$**	2004 $
G&A expenses	**6,434,136**	4,593,048
Overhead recoveries	**(5,754,607)**	(3,789,590)
Net G&A expenses	**679,529**	803,458

10. PERFORMANCE BASED COMPENSATION

The Trust awards performance based compensation to employees and key consultants annually. The performance based compensation is comprised of market and reserve value based components.

The reserves value based component is 3% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and distributions, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%.

($ million except unit values)	**2005**	**2004**	**Change**
Net present value of proved producing reserves @ 8% based on constant Paddock Lindstrom 2005 price forecast	2,121.0	1,691.0	
Net debt before performance based compensation	(257.4)	(223.0)	
2005 distributions	-	(136.6)	
Net value	1,863.6	1,331.4	532.2
Equity adjustment factor*			80%
Equity adjusted increase in value			427.1
2005 reserve value based compensation @ 3%			$12.8

*Equity adjustment factor is calculated as the percent increase in value per unit divided by the total percent increase in value

Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 7% of the total number of trust units outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. Compensation is calculated as the number of vested rights multiplied by the total of the market appreciation (over the price at the date of grant) and associated distributions of a trust unit for that period. A tax factor of 1.333 is then applied to determine the amount to be paid. The 2005 market based component was based on 2.0 million vested rights at an average grant price of $10.82, average cumulative distributions of $4.36 and the five day weighted average closing price of $25.38 (2004 – 2.0 million rights, average grant price of $8.41, average cumulative distributions of $1.365 per unit and five day weighted average closing price of $23.77, all 2004 comparatives adjusted to reflect the May 31, 2005 2 for 1 unit split). In the fourth quarter of 2005, there was a recovery of the previously recorded provision for future performance based compensation due to a reduction of trust unit market price.

The total amount expensed under these plans was as follows:

	2005 **$**	2004 $
Market based compensation	**45,045,054**	44,607,873
Reserve value based compensation	**12,802,000**	8,333,000
Total	**57,847,054**	52,940,873

For the market based component, compensation costs as at December 31, 2005 related to 2.6 million non-vested rights with an average grant price of $20.31 was $21.7 million of which a non-cash provision for future compensation expense of $6.1 million was recorded at December 31, 2004 and an additional $4.0 million was recorded in 2005.

11. FUTURE INCOME TAXES

	2005 **$**	2004 $
Earnings before income taxes	**199,660,706**	99,961,108
Statutory income tax rate	**37.62%**	38.87%
Expected income taxes	**75,112,358**	38,854,882
Increase (decrease) in income taxes from:		
Non-deductible crown charges	**24,372,435**	19,990,378
Resource allowance	**(21,705,862)**	(15,714,733)
Corporate income tax rate change	**(370,683)**	-
Attributed Canadian Royalty Income (ACRI)	**(1,023,253)**	2,205,065
Income attributed to the trust	**(38,423,907)**	(20,917,147)
Change in valuation allowance for share issue costs	**(994,416)**	-
Other	**651,293**	1,139,852
Future income tax expense	**37,617,965**	25,558,297

The net future income tax liability comprises:

	2005 **$**	2004 $
Differences between tax base and reported amounts for depreciable assets	**112,788,707**	81,931,159
Accrued expenditures	**(2,858,527)**	(10,103,715)
Provision for asset retirement obligation	**(1,637,214)**	(1,152,442)
	108,292,966	70,675,002

At December 31, 2005 the Trust has tax pools of approximately $582.4 million (December 31, 2004 - $303.9 million) available for deduction against future income. Peyto Energy Trust has approximately $9.3 million in unrecognized future income tax assets available to reduce future taxable income.

12. Financial Instruments

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Trust enters into these contracts with well established counterparties for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of petroleum and natural gas prices. The Trust believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Trust's firm commitment or forecasted transaction and the underlying basis of the instrument correlates highly with the Trust's exposure. A summary of contracts outstanding in respect of the hedging activities at December 31, 2005 is as follows:

Crude Oil Period Hedged	Type	Daily Volume	Weighted Average Price (CAD)
January 1 to March 31, 2006	Fixed price	1,300 bbl	$58.56/bbl
April 1 to June 30, 2006	Fixed price	1,100 bbl	$71.46/bbl
July 1 to September 30, 2006	Fixed price	900 bbl	$74.52/bbl
October 1 to December 31, 2006	Fixed price	600 bbl	$73.17/bbl

Natural Gas Period Hedged	Type	Daily Volume	Weighted Average Price (CAD)
Nov. 1, 2005 to March 31, 2006	Fixed price	75,000 GJ	$8.21/GJ
April 1 to October 31, 2006	Fixed price	50,000 GJ	$8.23/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	35,000 GJ	$10.01/GJ

As at December 31, 2005, the Trust had committed to the future sale of 355,100 barrels of crude oil at an average price of $68.19 per barrel and 22,735,000 gigajoules (GJ) of natural gas at an average price of $8.64 per GJ or $10.11 per mcf based on the historical heating value of Peyto's natural gas. These contracts will generate revenue totaling $220.6 million. Based on the market's estimate of the future commodity prices as at December 31, 2005 the fair value of these contracts would be $261.4 million.

Subsequent to December 31, 2005 the Trust entered into the following contracts:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.27/GJ

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2005 and 2004

Fair Values of Financial Assets and Liabilities

The Trust's financial instruments include accounts receivable, due from private placement, current liabilities, provision for future market performance based compensation and long term debt. At December 31, 2005, the carrying value of accounts receivable, due from private placement, current liabilities and provision for future market performance based compensation approximate their value due to their short term nature or method of determination. The carrying value of the long term debt approximates its fair value due to the floating rate of interest charged under the facilities.

Credit Risk

A substantial portion of the Trust's accounts receivable is with petroleum and natural gas marketing entities. The Trust generally extends unsecured credit to these companies, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Trust's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit. The Trust has not previously experienced any material credit losses on the collection of accounts receivable. Of the Trust's significant individual accounts receivable at December 31, 2005, approximately 42% was due from one company (December 31, 2004 – 50%).

The Trust may be exposed to certain losses in the event of non-performance by counter-parties to commodity price contracts. The Trust mitigates this risk by entering into transactions with counter-parties that have investment grade credit ratings.

Interest rate risk

The Trust is exposed to interest rate risk in relation to interest expense on its revolving demand facility. At December 31, 2005, the increase or decrease in earnings for each 1% change in interest rate paid on the outstanding revolving demand loan amounts to approximately $2.2 million per annum.

13. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital balances

	2005 **$**	2004 $
Accounts receivable	**(23,801,458)**	(17,881,727)
Due from private placement	**(370,181)**	(130,497)
Prepaid expenses and deposits	**3,467,237**	(18,066,972)
Accounts payable and accrued liabilities	**83,530,820**	43,326,215
Capital taxes payable	**(372,669)**	406,355
Cash distributions payable	**2,462,162**	2,258,543
	64,915,911	9,911,917
Attributable to financing activities	**2,091,981**	(15,808,428)
Attributable to investing activities	**27,047,091**	20,690,714
Attributable to operating activities	**35,776,839**	5,029,631

	2005 **$**	2004 $
Cash interest paid during the year	**8,701,501**	6,904,809
Cash taxes paid during the year	**847,669**	214,822

14. COMMITMENTS

The Trust is committed to payments under operating leases for office space as follows:

	$
2006	953,484
2007	953,484
2008	1,096,641
2009	1,096,641
2010	1,096,641
2011	1,096,641
	6,293,532

15. SUBSEQUENT EVENTS

On February 14, 2006, on private placement basis, 312,370 trust units were issued to employees and consultants at a price of $22.18 per trust unit for proceeds for $6.9 million.

Peyto Exploration & Development Corp. Information

Officers

Don Gray
President and Chief Executive Officer

Ken Veres
Vice-President, Exploration

Darren Gee
Vice President, Engineering

Scott Robinson
Vice President, Operations

Glenn Booth
Vice President, Land

Kathy Turgeon
Vice President, Finance

Stephen Chetner
Corporate Secretary

Cheree Stephenson
Controller

Directors

Ian Mottershead
Rick Braund
Don Gray
Brian Craig
Roberto Bosdachin
John Boyd
Michael MacBean

Auditors
Deloitte & Touche LLP

Solicitors
Burnet, Duckworth & Palmer LLP

Bankers
Bank of Montreal
Union Bank of California
Canadian Imperial Bank of Commerce
Royal Bank of Canada
BNP Paribas

Transfer Agent
Valiant Trust Company

Head Office
2900, 450 – 1st Street SW
Calgary, AB
T2P 5H1

Phone: 403.261.6081
Fax: 403.261.8976
Web: www.peyto.com

Stock Listing Symbol: PEY.un
Toronto Stock Exchange