PEYTO

Energy Trust

2006

Annual Report

Chairman's Message

The most satisfying activity in my career as an investment manager was identifying investments for durable long-term portfolios. This required focusing on a company's fundamental value and long-term prospects. The idea was to identify great companies as core portfolio positions and to hold them for a long time.

The most important message I wish to get across this year is that Peyto has been "designed" as a growing long-term investment with sustainable distributions in spite of the depleting nature of gas assets and the inherent cyclicality of natural gas markets.

We are currently in a significant down-cycle of the Peyto unit price caused by a downswing in natural gas prices, a flattening of production, a surprise increase in taxation proposed by the federal government, and some uncertainty associated with a change of the leadership of Peyto. Let me address each of these factors.

There is a self-correcting mechanism in natural gas markets. High gas well decline rates and reduced capital spending lead to quite swift supply reductions. Attractive natural gas prices relative to alternative energy sources lead to demand increases. The combination lead to a rise in the price of gas, and the process generally does not take long. The weather has a lot of impact on the precise timing.

Our Chief Executive Officer has commented elsewhere that unlike virtually all of our competitors, Peyto's unique assets mean that our current flat production is associated with increasing net asset value. Also, as time passes, and our wells mature, the corporate decline rate will fall, and it will become progressively easier to increase production. We just have to be patient.

I have little original to comment regarding the federal government's proposal to tax distributions commencing in four years time. With a minority government, the situation is still fluid. We do not know precisely what tax rules will eventually apply. Our analysis of the situation is ongoing. At the present time, it looks as though we are likely to carry on business as we have been for at least four years. We will assess the situation to ensure the most efficient organizational structure for Peyto beyond the four year period.

Peyto co-founder Don Gray retired as Chief Executive Officer on December 31, 2006. On behalf of the Board of Directors and the unit holders of Peyto, I thank Don for his profound contribution to the success of the enterprise over the last eight years. Most particularly, we should recognize that he was responsible for establishing essentially all the key strategic instructions which have determined Peyto's character. Examples of these include the following:

- focus Peyto management on building unit holder value which in time will be followed by production and distribution growth

- use Peyto's technical skills to grow via the drill bit rather than by acquisition – "design, drill and build" Peyto's assets

- make the distributions to unit holders truly sustainable

- distribute half the cash flow, and use the remainder to grow asset value

- develop assets with a long reserve life

- focus capital spending on projects with a high potential return on capital

- concentrate Peyto's assets entirely in tight gas plays in the Alberta Deep Basin

- establish a compensation plan that encourages Peyto employees to think and behave like owners

- establish a continuously layered-in hedge program to smooth effective natural gas prices received

We are pleased that Don will continue as an active director of Peyto, and is maintaining his large holding of Peyto units. Peyto unit holders can anticipate benefiting from his unusual set of business skills.

Darren Gee, formerly Vice President Engineering of Peyto, succeeded Don Gray as President in August of 2006 and as Chief Executive Officer at the beginning of 2007. The transition has been smooth. Darren is intimately familiar with the Peyto business model and its merits. I think that unit holders will be pleased with the continuity that Darren will provide. He will progressively put his own stamp on the enterprise. His President's Monthly Reports published on the Peyto website reveal him in both a reporting and teaching mode. They are well worth checking each month. Darren Gee joined the Board of Directors effective January 1, 2007.

Brian Craig, who was one of the original directors of Peyto, resigned from the Board in August, 2006. The Board much appreciated his counsel.

Brian Davis, a Houston-based oil and gas engineering consultant and a long time unit holder of Peyto, was appointed to the Board in August, 2006 and Greg Fletcher, an experienced Calgary-based oil and gas entrepreneur, was appointed to the Board effective January 1, 2007. Brian Davis was elected Chairman of the Peyto Reserves Committee, and as such, supervised the independent reserves assessment that has just taken place. This indicated that Peyto units are now trading at a significant discount to net asset value.

In the spirit of candor, which we owe to unit holders, I observe that some of Peyto's capital spending last year was not as effective as the Board expects. This problem was concentrated in the first quarter of 2006, and was associated with what we believe to have been too rapid growth in an environment of inflating service costs. As a result, it was decided to reduce the number of active rigs, and to live within the means of generated cash flow after distributions. Ongoing detailed analysis is confirming that capital efficiency is improving. Finding and development costs, which rose quite a lot last year, compare well with those of our competitors, but were above acceptable levels for Peyto, and we look for better numbers in 2007.

Over the last year, the Board has conducted a full review of Peyto's performance-based compensation plan. Alternatives to the existing plan were examined, but the Board affirmed that the combination of "average" base salaries with a market-based bonus (an option equivalent) and a reserves value based bonus for both the general staff of Peyto and the new Chief Executive Officer remain the most appropriate.

It should be noted, however, that the compensation plan structure has not been entirely static. Over the last three years, the quantity of grants under the market-based bonus plan has been steadily reduced as a percentage of units outstanding. The most recent grants no longer carry a 33% "tax factor". This had been introduced when the option plan was replaced in 2003 at the time of the conversion to a trust, and it adjusted for the difference between the tax rate on stock options (about 20%) and on the market based performance compensation (about 40%). In addition the reserves value based bonus has just been adjusted by increasing the percentage of net incremental value added of proved producing reserves paid out as bonuses from 3% to 4% commencing in the 2007 year.

The Board believes that Peyto's compensation plan aligns the interests of employees and unit holders, and rewards the key measures of performance. The after-tax proceeds of bonuses are almost entirely invested in Peyto units at the request of the employees. As a result, they are becoming larger owners of the enterprise.

As a final comment, I note that a period of weak natural gas prices is confirming the quality of Peyto's assets and the sustainability of Peyto's distributions. Most of Peyto's competitors have now reduced their distribution rates.

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, our low cost structure and our ability to profitably find and develop new oil and natural gas reserves, year after year. We are proud to present our operating and financial results for the fourth quarter and 2006 fiscal year.

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

- Long reserve life – Proved Producing 12 years, Total Proved 14 years, Proved plus Probable 20 years
- High netback - $39.25/boe
- Low operating costs - $2.16/boe
- Low base general and administrative costs - $0.48/boe
- High operatorship - over 95% of production
- Low cash distribution ratio - 57% of fourth quarter 2006 funds from operations
- Low debt to funds from operations ratio – 1.4 (net debt, before provision for future performance based compensation, divided by annualized fourth quarter 2006 funds from operations)
- Distribution growth - distributions have been increased 5 times, never decreased, and are now 87% higher than when the trust was formed three 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 $312 million in capital and created $914 million of Proved Producing and $1,197 million worth of Proved plus Probable undiscounted reserve value, translating into NPV recycle ratios of 2.9 and 3.8 respectively
- Asset value growth – the debt adjusted net present value of the trust's Proven plus Probable oil and gas assets, discounted at 5%, grew by 9% per trust unit to $30.75 in 2006
- Reserve growth per unit - proved producing reserves, grew 8% year over year
- Reserve life growth – Proven Producing reserve life grew from 11 years in 2005 to 12 years in 2006, while Proven plus Probable reserve life grew from 19 to 20 years.
- Distributions per unit - increased by 19% from $1.39 in 2005 to $1.66 in 2006.
- Distribution life growth – increased from 19 years in 2005 to 23 years in 2006 (based on undiscounted proven producing NPV and as defined herein)
- Annual production growth – increased 3% from 22,219 boe/d in 2005 to 22,873 boe/d in 2006
- Annual production per unit[(1)] – increased 1% year over year but decreased 9% per debt adjusted unit
- Annual funds from operations per unit[(1)] – increased 1% year over year but decreased 9% per debt adjusted unit
- Cost of new reserves (FD&A) – Proved Producing $17.67/boe, Total Proved $19.66/boe, Proved Plus Probable $17.39/boe (including change in future development capital)
- Recycle ratio – Proved Producing 2.0, Total Proved 1.8, Proved Plus Probable 2.0 (including change in future development capital)
- Reserve replacement – Proved Producing 211%, Total Proved 194%, Proved Plus Probable 220%

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 $17.70 for 2006 and $25.39 for 2005.

	3 Months Ended Dec. 31		%	12 Months Ended Dec. 31		%
	2006	2005	Change	**2006**	2005	Change
Operations						
Production						
Natural gas (mcf/d)	**112,296**	108,356	*4%*	**112,751**	106,701	*6%*
Oil & NGLs (bbl/d)	**3,834**	4,185	*(8)%*	**4,081**	4,436	*(8)%*
Barrels of oil equivalent (boe/d @ 6:1)	**22,550**	22,245	*1%*	**22,873**	22,219	*3%*
Product prices						
Natural gas ($/mcf)	**8.84**	10.55	*(16)%*	**8.46**	8.78	*(4)%*
Oil & NGLs ($/bbl)	**54.89**	58.43	*(6)%*	**61.00**	55.48	*10%*
Operating expenses ($/boe)	**2.69**	1.95	*38%*	**2.16**	1.55	*39%*
Transportation ($/boe)	**0.52**	0.70	*(26)%*	**0.58**	0.68	*(15)%*
Field netback ($/boe)	**40.85**	43.33	*(6)%*	**39.25**	37.83	*4%*
General & administrative expenses ($/boe)	**0.85**	0.05	*1600%*	**0.48**	0.08	*500%*
Interest expense ($/boe)	**2.72**	0.91	*199%*	**2.16**	1.07	*102%*
Financial ($000, except per unit)						
Revenue	**110,696**	127,633	*(13)%*	**439,008**	431,695	*2%*
Royalties (net of ARTC)	**19,271**	33,522	*(43)%*	**88,446**	106,802	*(17)%*
Funds from operations	**77,360**	86,607	*(11)%*	**305,845**	296,970	*3%*
Funds from operations per unit	**0.74**	0.85	*(13)%*	**2.93**	3.01	*(3)%*
Total distributions	**44,206**	36,773	*20%*	**173,755**	136,648	*27%*
Total distributions per unit	**0.42**	0.36	*17%*	**1.66**	1.39	*19%*
Payout ratio	**57**	42	*36%*	**57**	46	*24%*
Cash distributions (net of DRIP)	**44,206**	33,771	*31%*	**158,204**	127,094	*24%*
Payout ratio	**57**	39	*46%*	**52**	43	*21%*
Earnings	**47,012**	60,745	*(23)%*	**195,228**	161,568	*21%*
Earnings per diluted unit	**0.44**	0.60	*(27)%*	**1.86**	1.64	*13%*
Capital expenditures	**28,413**	107,647	*(74)%*	**311,926**	358,454	*(13)%*
Weighted average trust units outstanding	**105,251,394**	102,148,411	*3%*	**104,554,325**	98,576,640	*6%*
As at December 31						
Net debt (before future compensation expense)				**426,356**	287,885	*48%*
Unitholders' equity				**489,712**	421,831	*16%*
Total assets				**1,136,700**	944,927	*20%*

Net Earnings	**195,228**	161,568
Items not requiring cash:		
Provision for (recovery of) performance based compensation	**(10,149)**	(18,271)
Future income tax expense	**27,357**	37,618
Depletion, depreciation and accretion	**81,098**	58,208
Non-recurring items:		
Performance based compensation	**12,311**	57,847
Funds from operations [1]	**305,845**	296,970

[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.

Year in Review

Peyto is a conventional style energy company with unconventional assets and uncommon results. We explore for new reserves. We develop what we find. We operate what we produce. We sell our production and deliver part of the income to our unitholders while deploying the remaining capital to repeat this process and grow our asset base. Acquiring what others have found and developed has not yet met our rate of return objectives; the margins are just too thin. Funding additional exploration activity with equity or debt is fine, so long as the cost of this capital does not impair our returns or dilute our unitholders. We will continue to operate our business in this way regardless of our organizational structure. Our structure will adapt and evolve to ensure our income is distributed in the most tax efficient manner possible.

By all measures, 2006 was a challenging year. Natural gas prices (AECO monthly) changed dramatically throughout the year dropping 63% from highs of $11.48/GJ in January to lows of $4.22/GJ in October. In contrast, service costs continued to rise with CAODC (Canadian Association of Oilwell Drilling Contractors) labor rates increasing again in October 2006. The Finance Minister's announcement on October 31, 2006, relating to the taxation of trusts, sent unit prices tumbling. Navigating through these challenges tested our business strategy to its fullest. We recognized early in the year that, for the first time, our rates of return on capital invested were beginning to diminish. This was in part driven by declining commodity prices relative to increased service costs and in part due to a pace of development that was too aggressive. A conscious decision was made to slow down our pace of investment and refocus our attentions on those opportunities that delivered a premium return in this environment. This approach worked. Our FD&A costs and internal rates of return improved and are continuing to improve as illustrated in the following table.

	2006			
Full Cycle Investment Analysis	**Q1**	**Q2**	**Q3**	**Q4**
FD&A (Proved Producing, $/boe)	$19.35	$16.34	$15.27	$14.57
Internal Rate of Return (IRR)	17%	30%	39%	47%
Capital Expenditures ($ millions)	$145	$67	$71	$28

**Peyto internal evaluation based on actual well related capital spent (inclusive of land, seismic and facilities) and using Paddock Lindstrom and Associates reserve assignments and price forecasts.*

Peyto was able to adapt to these changing business conditions without compromising our strategy or cutting our distribution. Our internal standards for investment return remain as high as ever and we continually monitor our investment results to ensure we are meeting these expectations. We have emerged from 2006 with even more confidence that our focused approach, designed for managed growth and increased sustainability, continues to succeed.

Peyto has now achieved a milestone in its history. For the first time, we are operating solely on our internally generated capital, having delivered all of the unitholder's equity back in distributions. Since Peyto's inception, we have invested a total of $1.3 billion in capital, raised $404 million in unitholder's equity, distributed $445 million in distributions, and built an asset that is worth $3.7 billion ($3.3 billion after adjusting for debt, P+P NPV_5). Unfortunately, this does not mean that all unitholders have enjoyed their fair share of returns. At times our unit price has reflected our value, at other times it has not. What it does mean, however, is that our long life, low cost natural gas business has invested significantly less than the value we have created. We will continue to use our technical expertise and our ability to execute our ideas to create future wealth for our unitholders.

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's inception eight years ago.

Funding Sources for Capital Since Inception (from 1998 to 2006)	**($000)**	**% of Total**
Cash flow from projects found and developed by Peyto	898,928	70%
Net Equity (Equity issued of $403.5 million less Accumulated Distributions of $444.9 million)	(41,442)	(3)%
Net Debt (year end 2006 excluding future performance based compensation)	426,356	33%
Total Capital Expenditures	1,283,842	100%

Capital Expenditures

Net capital expenditures for 2006 totaled $312 million which was a decrease of 13% from 2005 reflecting a slow down in activity level in response to service cost inflation. Consistent with our "design, drill and build" strategy, 100% of the capital was invested to develop and produce new oil and gas reserves in Alberta's Deep Basin. Investment in processing facilities in the Wildhay and Nosehill areas accounted for $26 million and added 40 mmcf/d of additional gas plant capacity. Future drilling inventory was secured with an additional investment of $22 million in land and seismic. None of our 2006 capital was spent on acquisitions. The following table summarizes capital expenditures for the year.

	2006		**2005**		**Since Inception**	
Capital Expenditures	**($000)**	**% of Total**	**($000)**	**% of Total**	**($000)**	**% of Total**
Land	13,253	*4%*	12,324	*3%*	40,966	*3%*
Seismic	8,944	*3%*	11,559	*3%*	33,257	*3%*
Drilling & Completion – Exploratory & Development	227,585	*73%*	274,360	*77%*	929,527	*72%*
Production Equipment, Facilities & Pipelines	61,961	*20%*	59,810	*17%*	248,195	*19%*
Acquisitions & Dispositions	-	-	-	-	30,856	*3%*
Office Equipment	183	-	401	-	1,040	-
Total	311,926	*100%*	358,454	*100%*	1,283,842	*100%*

During the year, we drilled or re-entered 82 gross (66 net) gas wells. The average depth of our wells increased another 46m to 2606m, as our drilling prospects continue to evolve to include deeper Cretaceous zones. Most of our wells have at least two and sometimes three prospective gas bearing zones for development.

Reserves

During 2006, 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			
	2006	2005	% Change	% Change Per Unit (NPV_5 debt adjusted)
Reserves				
BOE 6:1 (mstb)				
Proved Producing	**97,181**	87,881	*11%*	*8%*
Total Proved	**118,681**	110,802	*7%*	*5%*
Proved + Probable Additional	**163,464**	153,448	*7%*	*4%*
Net Present Value ($million)				
Discounted at 5%				
Proved Producing	**2,462**	2,113	*17%*	*14%*
Total Proved	**2,869**	2,539	*13%*	*11%*
Proved + Probable Additional	**3,679**	3,219	*14%*	*12%*

Note: Based on the Paddock Lindstrom & Associates report effective December 31, 2006. 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, 2007 announcing our 2006 Year End Reserve Report which is 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 2007.

Value Creation

At Peyto we believe that value creation is the fundamental measure of our investment success. We quantify this by measuring the value created during the year compared to the capital invested, and do so to ensure the most efficient 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 Net Present Value (NPV) with this year's 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. In 2006, we created $914 million of Proved Producing and $1,197 million of Proved plus Probable undiscounted reserve value with $312 million in capital. Relative to our enterprise value, this amount of net value created represents a significant growth rate. The following table breaks out the value created by Peyto's capital investments and reconciles the changes in debt adjusted NPV of future net revenues using forecast prices and costs as at December 31, 2006.

	Proven Producing		Total Proven		Proven + Probable Additional	
($millions) Discounted at	0%	5%	0%	5%	0%	5%
Net Present Value at Beginning of Year ($millions) Dec. 31, 2005 Evaluation using PLA Jan. 1, 2006 price forecast, debt adjusted	**$3,248**	**$1,816**	**$4,075**	**$2,242**	**$5,709**	**$2,922**
Per Unit Outstanding at Dec. 31, 2005 ($/unit)	$31.40	$17.55	$39.39	$21.76	$55.18	$28.24
2006 sales (revenue less royalties and operating costs)	($328)	($328)	($328)	($328)	($328)	($328)
Net Change due to price forecasts (using PLA Jan 1, 2007 price forecast)	$232	$49	$298	$64	$481	$114
Net Change due to discoveries (additions, extensions, transfers, revisions)	$914	$491	$915	$457	$1,197	$537
Net Present Value at End of Year ($millions) Dec. 31, 2006 Evaluation using PLA Jan. 1, 2007 price forecast, debt adjusted	**$4,066**	**$2,029**	**$4,961**	**$2,435**	**$7,059**	**$3,245**
Per Unit Outstanding at Dec. 31, 2006 ($/unit)	$38.53	$19.22	$47.01	$23.08	$66.88	$30.75

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. We believe that the value analysis presented above is the best measure of profitability, as it compares the value of what was created relative to what was invested, or what we term, the Net Present Value (NPV) recycle ratio. 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 2006 our Proven plus Probable NPV recycle ratio was 3.8 times, up from 3.2 times in 2005. This means for each dollar we invested we were able to create 3.8 new dollars of Proven plus Probable reserve value.

2006 Value Creation	**Dec 31, 2006**	Dec 31, 2005	% Change
NPV Recycle Ratio			
Proven Producing	2.9	2.5	*17%*
Total Proven	2.9	2.8	*6%*
Proven + Probable	3.8	3.2	*19%*

- 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.

We present other measures for comparative purposes, such as FD&A, recycle ratio and reserve replacement ratio, but caution that they are incomplete and on their own do not measure success.

For the second year in a row, our reserves grew faster than our production. This resulted in an increase in reserve life for all of the reserve categories. Our Proven plus Probable reserve life grew from 19 years at the end of 2005 to 20 years at the end of 2006. Along with this reserve life growth was a growth in the assets that fund distributions. Our distribution life grew from 19 years to 23 years for the Proved Producing category, increasing our sustainability.

2006 Performance Ratios	**Proved Producing**	**Total Proved**	**Proved + Probable**
Reserve life index (years)			
Q4 2006 average production – 22,550 boe/d	12	14	20
Finding, development and acquisition costs ($/boe)			
(Including change in future development capital)	$17.67	$19.66	$17.39
Reserve replacement ratio	2.1	1.9	2.2
Recycle ratio			
(Including change in future development capital)	2.0	1.8	2.0
Distribution life (years)	23	28	40

- The reserve life index is calculated by dividing the reserves (in boes) in each category by the annualized average production rate in boe/year (eg. Proved Producing 97,181/(22.550*365)=12). Peyto believes that the most accurate way to evaluate the current reserve life is by dividing the proved developed producing reserves by the actual fourth quarter annualized production. In our opinion, for comparative purposes, the proved developed producing reserve life provides 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. Subsequent to NI 51-101 in 2003, FD&A costs are calculated including the change in future development capital ("FDC") (eg. Proved Producing = $312MM/17.65mmboes = $17.67/boe).
- The reserve replacement ratio is determined by dividing the yearly change in reserves before production by the actual annual production for the year (eg. Proved Producing ((97,181-87,881+8,350)/8,350)=2.1).
- Recycle ratio is calculated by dividing the field net back per boe, before hedging, by the FD&A costs for the period (eg. Proven Producing ($39.25/boe-$4.53/boe)/$17.67/boe = 2.0). 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.
- The distribution life is calculated by dividing the debt adjusted undiscounted NPV by the Q4 annualized distribution (eg. Proved Producing $4,066 million/(44.2*4) million/year = 23 years).

Quarterly Review

Daily production for the three months averaged 112 mmcf of natural gas and 3,834 barrels of oil and natural gas liquids. Reductions in production and commodity prices decreased funds from operations from $86.6 million in Q4 2005 to $77.4 million in Q4 2006. Peyto's commodity prices, net of hedging, decreased by 16% to average $8.84 per mcf of natural gas, and by 6% to average $54.89 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 $2.69/boe in the fourth quarter of 2006 compared to $1.95/boe for the fourth quarter of 2005. Cost inflation was observed for two main components of our cost structure; chemicals and labor. Methanol, which comprises approximately 20% of our costs, increased by 50% over the course of the year. In addition, labor costs also increased with the elevated level of industry activity. 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 $28.4 million, the lowest for the period since 2001, reflecting our dramatic slow down of activity in response to continued service cost inflation. Only our premium opportunities attracted our capital dollars. As usual, well related activity made up 94% of this capital, with drilling and completion costs accounting for $22.8 million while facilities and tie-ins accounted for $5.0 million. Peyto spent $0.5 million on land and seismic in the quarter.

Activity Update

Peyto has entered 2007 with a measured approach to capital spending as service sector costs remain too high relative to commodity prices. Over the first quarter of 2007, we expect to continue our present pace of capital spending which we currently anticipate will be less than retained cash flow. At this time, we are employing 3 drilling rigs targeting our premium quality opportunities. We stand poised with over 100 drill ready locations and can increase our activity level quickly when we see a reduction in service costs or an increase in commodity prices.

To date in 2007, we have drilled and cased 8 gross gas wells (5.4 net) with very positive results. Drilling has focused in the Greater Sundance area where we have a high concentration of low risk multi-zone development opportunities. Thus far, we have connected and brought onstream 5.8 net wells (10.7 net zones). The 2007 new wells have begun to replace the natural decline of our base production with current production around the 22,000 boed level. In addition to Sundance, recent drilling in two new expansion areas called Pine Creek and Chime follow up successful discoveries and continue to seed our future.

Marketing

By design, Peyto's marketing strategy smoothes 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 break even on our forward sales (cum to date - $6 million gain). Our hedging approach is based on a forward average price typically made up of fifteen to twenty transactions placed 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 $7.08/mcf during the fourth quarter of 2006, a decrease of 44% from $12.60/mcf reported for the equivalent period in 2005. Oil and natural gas liquids prices averaged $51.60/bbl down 18% from $63.27/bbl a year earlier. Hedging activity for the fourth quarter of 2006 increased Peyto's achieved price by $9.30/boe. The fourth quarter hedging gain was $19.3 million, for a year to date total gain of $37.8 million (2005 hedging loss $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	
	2006	2005	**2006**	2005
Natural gas ($/mcf)	**7.08**	12.60	**7.50**	9.62
Hedging – gas ($/mcf)	**1.76**	(2.05)	**0.96**	(0.84)
Natural gas – after hedging ($/mcf)	**8.84**	10.55	**8.48**	8.78
Oil and natural gas liquids($/bbl)	**51.60**	63.27	**62.11**	59.62
Hedging – oil ($/bbl)	**3.29**	(4.84)	**(1.11)**	(4.14)
Oil and natural gas liquids – after hedging ($/bbl)	**54.89**	58.43	**61.00**	55.48
Total Hedging ($/boe)	**9.30**	(10.93)	**4.53**	(4.88)

Revenue	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2006**	2005	**2006**	2005
Natural gas	**73,192**	125,651	**308,692**	374,750
Oil and natural gas liquids	**18,200**	24,359	**92,523**	96,532
Hedging gain (loss)	**19,304**	(22,377)	**37,793**	(39,587)
Total revenue	**110,696**	127,633	**439,008**	431,695

As at December 31, 2006, Peyto had committed to the forward sale of 145,400 barrels of crude oil at an average price of $86.45 per barrel and 16.2 million gigajoules (GJ) of natural gas at an average price of $8.54 per GJ. Based on the historical heating value of Peyto's natural gas, the price per mcf of the forward sale will be $9.99, which is 18% higher than the price Peyto realized in 2006. If we realize the market's estimate for future commodity prices, as at December 31, 2006, this forward sale represents a 29% premium.

Performance Based Compensation

When Peyto converted to a trust in July, 2003, a 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, more conservatively 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 2006 was $12.3 million (market component - $8.5 million; reserve value component - $3.8 million). After the performance based compensation payments, private placements are offered to Peyto employees and consultants. Unlike typical option plans, the employees of Peyto have voluntarily 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. We have now distributed a total of $444.9 million or $4.255 per unit (adjusted for 2 for 1 split) to our unitholders. Since converting to a trust, we have returned 55% of the unit price at time of conversion, while increasing the reserves per unit by 73% and the production per unit by 37%.

Outlook

For Peyto, 2007 is setting up to be an exciting year. We believe that the land and seismic acquired in 2006 will lead to the exploration and development of several new fields. New facilities that were ordered in 2005 and installed in 2006, in anticipation of a continued aggressive pace of development, now have idle capacity. We are well positioned with this available capacity to handle continued development and expansion of core areas. We remain poised to capitalize on service cost reductions that the industry is anticipating later this year. The total amount of capital we ultimately invest in 2007 will be driven, as always, 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. Capital expenditures will continue to be funded with a combination of funds from operations, working capital, and bank lines. We will use equity only if it makes good sense to do so. The commodity prices continue to strengthen and our marketing program has already secured strong prices for the summer period.

We have now completed our eighth year as a developer of natural gas assets. We continue to execute the same strategy we began with in 1998. We believe there is more money to be made in the Canadian oil patch, and we plan to continue doing just that for our unitholders. 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.

Annual General Meeting

The Trust's Annual General Meeting of Unitholders is scheduled for 2:30 p.m. on Tuesday, May 29, 2007 at the Telus Convention Centre, Macleod Hall A, 120 – 9th Avenue SE, Calgary, Alberta.

Darren Gee
President and Chief Executive Officer
March 7, 2007

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, 2006 and 2005. 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. 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 7, 2007. 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).

Proposed Tax Legislation

On October 31, 2006, the Minister of Finance announced its proposal to amend the Income Tax Act (Canada) to apply a Distribution Tax on distributions from publicly-traded income trusts. Under the proposal, existing income trusts will be subject to the new measures commencing in their 2011 taxation year, following a four-year grace period. The Minister of Finance has issued a Notice of Ways and Means Motion to Amend the Income Tax Act, but it is not known at this time if or when the proposal will be enacted by Parliament. In simplified terms, under the proposed tax plan, income distributions will first be taxed at the trust level at a special rate estimated to be 31.5%. Income distributions to individual unitholders will then be treated as dividends from a Canadian corporation and eligible for the dividend tax credit. Income distributions to corporations resident in Canada will be eligible for full deduction as tax free intercorporate dividends. Tax-deferred accounts (RRSPs, RRIFs and Pension Plans) will continue to pay no tax on distributions. Non-resident unitholders will be taxed on distributions at the non-resident withholding tax rate for dividends. The net impact on Canadian taxable investors is expected to be minimal because they can take advantage of the dividend tax credit. However, as a result of the 31.5% Distribution Tax at the trust level, distributions to tax-deferred accounts will be reduced by approximately 31.5%, and distributions to non-residents will be reduced by approximately 26.5%. We are currently assessing the proposals and the potential implications to the Trust. We will continue to review structural alternatives to ensure that Peyto's structure is as efficient as possible.

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, 2006, we had total proved plus probable reserves of 163.5 million barrels of oil equivalent with a reserve life of 20 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 with the objective to deliver growth in its assets, production and income, all on a per unit basis. The model is built around three key principles:

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

Operating results over the last eight 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)	**2006**	2005	2004
Total revenue (before royalties)	**439,008**	431,695	300,501
Funds from operations	**305,845**	296,970	209,106
Per unit – basic*	**2.93**	3.01	2.28
Per unit – diluted*	**2.93**	3.01	2.28
Earnings (loss)	**195,228**	161,568	73,782
Per unit – basic*	**1.86**	1.64	0.805
Per unit – diluted*	**1.86**	1.64	0.805
Total assets	**1,136,700**	944,927	622,577
Total long-term debt	**420,000**	180,000	180,000
Cash distributions per unit*	**1.66**	1.39	1.02

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

QUARTERLY FINANCIAL INFORMATION

	2006				2005			
($000 except per unit amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue (net of royalties)	**91,425**	84,164	88,515	86,459	94,111	84,912	73,473	72,397
Funds from operations	**77,360**	72,360	77,507	78,617	86,607	77,179	66,548	66,636
Per unit – basic*	**0.74**	0.69	0.74	0.76	0.85	0.78	0.69	0.69
Per unit – diluted*	**0.74**	0.69	0.74	0.76	0.85	0.78	0.69	0.69
Earnings (loss)	**47,012**	46,155	56,768	45,293	60,745	37,702	25,690	37,431
Per unit – basic*	**0.44**	0.44	0.54	0.44	0.60	0.38	0.27	0.39
Per unit – diluted*	**0.44**	0.44	0.54	0.44	0.60	0.38	0.27	0.39

*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	
	2006	2005	**2006**	2005
Natural gas (mmcf/d)	**112,296**	108,356	**112,751**	106,701
Oil & natural gas liquids (bbl/d)	**3,834**	4,185	**4,081**	4,436
Barrels of oil equivalent (boe/d)	**22,550**	22,245	**22,873**	22,219

Natural gas production averaged 112.3 mmcf/d in the fourth quarter of 2006, 4 percent higher than the 108.4 mmcf/d reported for the same period in 2005. Oil and natural gas liquids production averaged 3,834 bbl/d, a decrease of 8 percent from 4,185 bbl/d reported in the prior year. Production for the year increased 3 percent from 22,219 boe/d to 22,873 boe/d. The production increases are directly attributable to Peyto's ongoing drilling program and are offset by our natural decline rates.

Commodity Prices

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2006	2005	**2006**	2005
Natural gas ($/mcf)	**7.08**	12.60	**7.50**	9.62
Hedging – gas ($/mcf)	**1.76**	(2.05)	**0.96**	(0.84)
Natural gas – after hedging ($/mcf)	**8.84**	10.55	**8.46**	8.78
Oil and natural gas liquids($/bbl)	**51.60**	63.27	**62.11**	59.62
Hedging – oil ($/bbl)	**3.29**	(4.84)	**(1.11)**	(4.14)
Oil and natural gas liquids – after hedging ($/bbl)	**54.89**	58.43	**61.00**	55.48
Total Hedging ($/boe)	**9.30**	(10.93)	**4.53**	(4.88)

Our natural gas price before hedging averaged $7.08/mcf during the fourth quarter of 2006, a decrease of 44 percent from $12.60/mcf reported for the equivalent period in 2005. Oil and natural gas liquids prices averaged $51.60/bbl down 18 percent from $63.27/bbl a year earlier. Average natural gas prices for the year were down 22 percent at $7.50/mcf while oil and natural gas liquids prices were up 4 percent at $62.11/bbl compared to 2005. Hedging activity for fiscal 2006 increased Peyto's price achieved by $4.53/boe.

Revenue

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2006**	2005	**2006**	2005
Natural gas	**73,192**	125,651	**308,692**	374,750
Oil and natural gas liquids	**18,200**	24,359	**92,523**	96,532
Hedging gain (loss)	**19,304**	(22,377)	**37,793**	(39,587)
Total revenue	**110,696**	127,633	**439,008**	431,695

For the three months ended December 31, 2006, gross revenue decreased 13 percent to $110.7 million from $127.6 million for the same period in 2005. The decrease in revenue for the quarter was a result of weaker commodity prices and decreased production volumes for oil and NGL. Revenues for the year increased due to increased gas volumes, as detailed in the following table.

	Three Months ended Dec 31			Twelve Months ended Dec. 31		
	2006	2005	**$million**	2006	2005	**$million**
Total Revenue, Dec 31, 2005			**127.6**			**431.7**
Revenue change due to:						
Natural gas						
Volume (mmcf)	10,331	9,969	**3.8**	41,154	38,946	**19.4**
Price ($/mcf)	$8.84	$10.55	**(17.7)**	$8.46	$8.78	**(13.1)**
Oil & NGL						
Volume (mbbl)	353	385	**(1.8)**	1,490	1,619	**(7.2)**
Price ($/bbl)	$54.89	$58.43	**(1.2)**	$61.00	$55.48	**8.2**
Total Revenue, Dec 31, 2006			**110.7**			**439.0**

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	
	2006	2005	**2006**	2005
Royalties, net of ARTC ($000)	**19,271**	33,522	**88,446**	106,802
% of sales	**18**	26	**21**	25
$/boe	**9.29**	16.38	**10.59**	13.17

For the fourth quarter of 2006, royalties averaged $9.29/boe or approximately 18 percent of Peyto's total petroleum and natural gas sales. Year to date royalties were 21 percent of sales in 2006 compared to 25 percent in 2005. 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 and that hedging gains and losses are not subject to royalties. As our average per well production rate declines, the associated effective Crown Royalty rate will decrease. In addition, Peyto receives Deep Gas Royalty Holiday benefits and Alberta Royalty Tax Credits which further decrease our crown royalty rate.

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	
	2006	2005	**2006**	2005
Operating costs ($000)				
Field expenses	**7,361**	5,347	**25,765**	17,609
Processing and gathering income	**(1,780)**	(1,354)	**(7,719)**	(5,063)
Total operating costs	**5,581**	3,993	**18,046**	12,546
$/boe	**2.69**	1.95	**2.16**	1.55
Transportation	**1,089**	1,433	**4,856**	5,520
$/boe	**0.52**	0.70	**0.58**	0.68

Operating costs were $5.6 million in the fourth quarter of 2006 compared to $4.0 million during the same period a year earlier. On a unit-of-production basis, operating costs averaged $2.69/boe in the fourth quarter of 2006 compared to $1.95/boe for the fourth quarter of 2005. Operating costs for the year averaged $2.16/boe in 2006 compared to $1.55/boe in 2005. Cost inflation during 2006 significantly impacted two main components of our cost structure: chemicals and labor. Transportation expense remained constant and was lower on a per boe basis.

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.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($/boe)	**2006**	2005	**2006**	2005
Sale Price	**53.35**	62.36	**52.58**	53.23
Less:				
Royalties	**9.29**	16.38	**10.59**	13.17
Operating costs	**2.69**	1.95	**2.16**	1.55
Transportation	**0.52**	0.70	**0.58**	0.68

Operating netback	**40.85**	43.33	**39.25**	37.83
General and administrative	**0.85**	0.05	**0.48**	0.08
Interest on long-term debt	**2.72**	0.91	**2.16**	1.07
Capital tax	**-**	0.06	**-**	0.06
Cash netback	**37.28**	42.31	**36.61**	36.62

General and Administrative Expenses

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2006	2005	**2006**	2005
G&A expenses ($000)	**2,426**	1,874	**9,397**	6,434
Overhead recoveries	**(669)**	(1,778)	**(5,431)**	(5,754)
Net G&A expenses	**1,757**	96	**3,966**	680
$/boe	**0.85**	0.05	**0.48**	0.08

General and administrative expenses before overhead recoveries increased to $2.4 million in the fourth quarter of 2006, as compared to $1.8 million for the same period in 2005 due to an increase in staffing and associated costs. Net of overhead recoveries associated with our capital expenditures program, general and administrative costs increased to $0.85 per boe in the fourth quarter of 2006, from $0.05 per boe in the fourth quarter of 2005. Fourth quarter 2006 capital overhead recoveries were 61% lower than fourth quarter 2005 recoveries. General and administrative expenses for 2006 averaged $0.48/boe in 2006 compared to $0.08 in 2005. Peyto has decreased reliance on third party consulting and replaced these services with staff positions resulting in increased general and administrative costs. This strategy has resulted in an over-all cost decrease to the Trust.

Interest Expense

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2006	2005	**2006**	2005
Interest expense ($000)	**5,638**	1,857	**18,011**	8,702
$/boe	**2.72**	0.91	**2.16**	1.07

2006 interest expense was $18.0 million or $2.16/boe compared to $8.7 million or $1.07/boe a year earlier. Average bank debt for 2006 was $360 million as compared to $221 million for 2005. Interest rates continue to be favorable and are not expected to increase substantially in the short-term.

Depletion, Depreciation and Accretion

The 2006 provision for depletion, depreciation and accretion totaled $81.1 million as compared to $58.2 million in 2005. On a unit-of-production basis, depletion, depreciation and accretion costs averaged $9.71/boe as compared to $7.18/boe in 2005. Increases or decreases in the depletion rate on a unit-of-production basis are influenced by the reserves added through Peyto's drilling program.

Income Taxes

The current provision for future income tax decreased to $27.4 million in 2006 from $37.6 million in 2005. Included in the 2006 provision was an amount of $8.0 million recorded in the fourth quarter (2005 - $8.8 million). Our trust structure is unique and was designed to provide for discretion at the operating trust level to distribute taxable income to the Trust. Our capital program generates resource pools which are available to offset current and future income tax liabilities. Unitholders benefit as the use of these resource pools increases the tax free return of capital component of the cash distributions. At December 31, 2006 the Trust has tax pools of approximately $670.8 million (December 31, 2005 - $582.4 million) available for deduction against future income.

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 2006, we recorded a hedging gain of $37.8 million as compared to a hedging loss of $39.6 million in 2005. 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, 2007	Fixed price	200 bbl	$82.82/bbl
January 1 to March 31, 2007	Fixed price	200 bbl	$87.35/bbl
January 1 to March 31, 2007	Fixed price	200 bbl	$88.00/bbl
April 1 to June 30, 2007	Fixed price	200 bbl	$82.39/bbl
April 1 to June 30, 2007	Fixed price	200 bbl	$87.10/bbl
April 1 to June 30, 2007	Fixed price	200 bbl	$88.05/bbl
July 1 to September 30, 2007	Fixed price	200 bbl	$87.61/bbl
July 1 to September 30, 2007	Fixed price	200 bbl	$88.20/bbl
July 1 to September 30, 2007	Fixed price	200 bbl	$77.12/bbl
October 1 to December 31, 2007	Fixed price	200 bbl	$77.51/bbl
January 1 to March 31, 2008	Fixed price	200 bbl	$78.55/bbl

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
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
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.65/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$10.25/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	$8.65/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.23/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$8.60/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.50/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.25/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.51/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.50/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.60/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.60/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.80/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.50/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.70/GJ
April 1, 2007 to March 31, 2008	Fixed price	5,000 GJ	$8.90/GJ
April 1, 2007 to March 31, 2008	Fixed price	5,000 GJ	$8.35/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. In the short term, this risk is mitigated indirectly as a result of our commodity hedging strategy as we hedge in Canadian currency. Over the long term, the Canadian dollar tends to rise as oil prices rise. There is a similar correlation between oil and gas prices. Currently we have not entered into any agreements to further 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, 2006, the increase or decrease in earnings for each 100 bps change in interest rate paid on the outstanding revolving demand loan amounts to approximately $3.6 million per annum.

LIQUIDITY AND CAPITAL RESOURCES

Funds from Operations

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2006**	2005	**2006**	2005
Net earnings	**47,012**	60,745	**195,228**	161,568
Items not requiring cash:				
Provision for (recovery of) performance based compensation	**(10,340)**	(57,459)	**(10,149)**	(18,271)
Future income tax expense	**7,980**	8,832	**27,357**	37,618
Depletion, depreciation & accretion	**20,397**	16,642	**81,098**	58,208
Non-recurring items:				
Market and reserve value performance based compensation	**12,311**	57,847	**12,311**	57,847
Funds from operations	**77,360**	86,607	**305,845**	296,970

For the quarter ended December 31, 2006, funds from operations totaled $77.4 million or $0.74 per unit, representing a 23 percent decrease from the $86.6 million, or $0.85 per unit during the same period in 2005. For fiscal 2006 funds from operations totaled $305.8 million or $2.93 per unit compared to $297.0 million or $3.01 per unit in 2005. 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 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 $450 million including a $430 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 2006 was 5.0% (2005 – 4.0%).

At December 31, 2006, $420 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, 2006, we had a working capital deficit of $13.6 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. The total amount of capital we invest in 2007 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. 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. Both the DRIP and the OTUPP were suspended effective August 31, 2006 due to unfavorable market conditions.

On December 31, 2006 the Trust completed a private placement of 285,190 trust units to employees and consultants for net proceeds of $5,042,159. These trust units were issued on January 8, 2007. On January 8, 2007, subsequent to the issuance of these units, 105,536,584 trust units were outstanding (December 31, 2006 – 105,251,394).

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

Trust Units (no par value) ($000)	**Number of Units**	**Amount $**
Balance, December 31, 2004	47,725,272	138,953
Trust units issued by private placement	670,000	31,586
Trust unit issue costs	-	(103)
Trust units issued pursuant to DRIP	28,645	1,356
Trust units issued pursuant to 2 for 1 split	48,423,917	-
Trust units issued by public offering	5,000,000	152,750
Trust unit issue costs	-	(8,054)
Trust units issued pursuant to DRIP	279,561	7,448
Trust units issued pursuant to OTUPP	206,452	4,800
Balance, December 31, 2005	102,333,847	328,736
Trust units issued by private placement	1,393,940	34,378
Trust units issued pursuant to DRIP	690,387	16,301
Trust units issued pursuant to OTUPP	833,220	19,019
Balance, December 31, 2006	**105,251,394**	**398,434**

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%.

($millions except unit values)	**2006**	**2005**	**Change**
Net present value of proved producing reserves @ 8% based on constant Paddock Lindstrom 2007 price forecast	1,728.6	1,575.9	
Net debt before performance based compensation	(426.4)	(287.9)	
2006 distributions	-	(173.8)	
Net value	1,302.2	1,114.2	188.0
Equity adjustment factor*			81%
Equity adjusted increase in value			152.3
2006 reserve value based compensation @ 3%			$4.6

*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 2006 market based component was based on 1.5 million vested rights (all of which were granted prior to May 2004) at an average grant price of $18.77, average cumulative distributions of $3.86 and the five day weighted average closing price of $17.68. In 2006, 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:

($000)	**2006** **$**	2005 $
Market based compensation	**8,491**	45,045
Reserve value based compensation	**4,570**	12,802
Recovery of prior year unpaid reserve bonus	**(750)**	-
Total	**12,311**	57,847

For the market based component, compensation costs as at December 31, 2006 related to 2.7 million non-vested rights with an average grant price of $24.78 were nil (2005 - $21.7 million).

Capital Expenditures

Net capital expenditures for the fourth quarter of 2006 totaled $28.4 million. Exploration and development related activity represented $22.8 million or 80% of the total, while expenditures on facilities, gathering systems and equipment totaled $5.0 million or 18% of the total. The following table summarizes capital expenditures for the year.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2006**	2005	**2006**	2005
Land	**-**	3,657	**13,253**	12,324
Seismic	**583**	3,309	**8,944**	11,559
Drilling – Exploratory & Development	**22,777**	84,189	**227,585**	274,360
Production Equipment, Facilities & Pipelines	**5,036**	16,308	**61,961**	59,810
Acquisitions & Dispositions	**-**	-	**-**	-
Office Equipment	**17**	184	**183**	401
Total Capital Expenditures	**28,413**	107,647	**311,926**	358,454

Cash Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2006	2005	**2006**	2005
Funds from operations ($000)	**77,360**	86,607	**305,845**	296,970
Total distributions ($000)	**44,206**	36,773	**173,755**	136,648
Total distributions per unit ($)*	**0.42**	0.36	**1.66**	1.39
Payout ratio (%)	**57**	42	**57**	46
Cash distributions ($000) (net of DRIP)	**44,206**	33,771	**158,204**	127,094
Payout ratio (%)	**57**	39	**52**	43

*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. The Board of Directors 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:

($000)	$
2007	953
2008	1,097
2009	1,097
2010	1,097
2011	1,097
	5,341

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.

RELATED PARTY TRANSACTIONS

During the period ended March 31, 2006, the Trust participated in a joint venture capital project with a company whose director was also a Peyto director until May 16, 2006. The Trust's participation in this joint venture amounted to $620,218. Costs associated with this joint venture capital project were billed and paid in accordance with normal business operations.

An officer of the Trust is a partner of a law firm that provides legal services to the Trust. The fees charged are based on standard rates and time spent on matters pertaining to the Trust and its subsidiaries. For the year ended December 31, 2006, legal fees totaled $695,563.

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 2006, the Trust paid distributions to the unitholders in the amount of $173.8 million (2005 - $136.7 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit*
January 2006	January 31, 2006	February 15, 2006	$0.12
February 2006	February 28, 2006	March 15, 2006	$0.14
March 2006	March 31, 2006	April 13, 2006	$0.14
April 2006	April 30, 2006	May 15, 2006	$0.14
May 2006	May 31, 2006	June 15, 2006	$0.14
June 2006	June 30, 2006	July 14, 2006	$0.14
July 2006	July 31, 2006	August 15, 2006	$0.14
August 2006	August 31, 2006	September 15, 2006	$0.14
September 2006	September 30, 2006	October 13, 2006	$0.14

October 2006	October 31, 2006	November 15, 2006	$0.14
November 2006	November 30, 2006	December 15, 2006	$0.14
December 2006	December 31, 2006	January 15, 2007	$0.14
			$1.66

*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, if appropriate, equity.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's management as appropriate to allow timely decisions regarding required disclosure. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the Trust's annual filings for the most recently completed financial year, that the Trust's disclosure controls and procedures as of the end of such period are effective to provide reasonable assurance that material information related to the Trust, including its consolidated subsidiaries, is made known to them by others within those entities.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

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

The Trust's Chief Executive Officer and Chief Financial Officer are required to cause the Trust to disclose herein any change in the Trust's internal control over financial reporting that occurred during the Trust's most recent interim period that materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. During 2006, the Trust engaged external consultants to assist in documenting and assessing the Trust's design of internal controls over financial reporting. No material changes were identified in the Trust's internal control of financial reporting during the three months ended December 31, 2006, that had materially affected, or are reasonably likely to materially affect, the Trust's internal control of financial reporting.

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

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, 2006 were audited by independent petroleum engineers Paddock Lindstrom & Associates Ltd. Paddock has been evaluating reserves in this area and for Peyto for 8 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 2007. 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 Canadian Institute of Chartered Accountants (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.

Distributable Cash

The Canadian Institute of Chartered Accountants (CICA) has issued draft guidance on the calculation and disclosure of distributable cash. As well, the Canadian Securities Administrators (CSA) has proposed amendments to National Policy (NI) 41-201 – Income trusts and other indirect offerings, the most significant of which relates to distributable cash. The intent of both of these documents is to address inconsistencies and financial reporting shortcomings in the calculation and disclosure of distributable cash, improving transparency regarding the sources of distributable cash to help investors assess the sustainability of distributions. Both of these draft documents are currently out for comment. The Trust will comply with any CICA standard or CSA NI 41-201 amendment when issued in final form.

ADDITIONAL INFORMATION

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

Quarterly information

	2006				2005	
	Q4	Q3	Q2	Q1	Q4	Q3
Operations						
Production						
Natural gas (mcf/d)	**112,296**	115,304	112,484	110,878	108,356	108,460
Oil & NGLs (bbl/d)	**3,834**	4,205	4,145	4,143	4,185	4,569
Barrels of oil equivalent (boe/d @ 6:1)	**22,550**	23,422	22,892	22,622	22,245	22,646
Average product prices						
Natural gas ($/mcf)	**8.84**	7.81	7.96	9.26	10.55	8.67
Oil & natural gas liquids ($/bbl)	**54.89**	64.50	66.94	57.12	58.43	57.22
Average operating expenses ($/boe)	**2.69**	1.90	2.26	1.81	1.95	1.70
Average transportation costs ($/boe)	**0.52**	0.58	0.59	0.63	0.70	0.66
Field netback ($/boe)	**40.85**	36.58	39.64	40.02	43.33	38.39
General & administrative expense ($/boe)	**0.85**	0.55	0.43	0.06	0.05	0.13
Interest expense ($/boe)	**2.72**	2.52	2.00	1.36	0.91	1.16
Financial ($000 except per unit)						
Revenue	**110,696**	107,844	106,751	113,717	127,633	110,566
Royalties (net of ARTC)	**19,271**	23,680	18,236	27,258	33,522	25,654
Funds from operations	**77,360**	72,360	77,507	78,617	86,607	77,179
Funds from operations per unit	**0.74**	0.69	0.74	0.76	0.85	0.78
Total distributions	**44,206**	44,111	43,921	41,517	36,773	35,505
Total distributions per unit	**0.42**	0.42	0.42	0.40	0.36	0.36
Payout ratio	**57%**	61%	57%	53%	42%	46%
Cash distributions (net of DRIP)	**44,206**	41,019	38,315	34,665	33,771	32,318
Payout ratio	**57%**	57%	49%	44%	39%	42%
Earnings	**47,012**	46,155	56,768	45,293	60,745	37,702
Earnings per diluted unit	**0.44**	0.44	0.54	0.44	0.60	0.38
Capital expenditures	**28,413**	71,223	67,195	145,094	107,647	93,001
Weighted average trust units outstanding	**105,251,394**	104,924,702	104,472,570	103,910,640	102,148,411	98,584,597

Deloitte.

To the Unitholders of:
Peyto Energy Trust:

Auditors' Report

We have audited the consolidated balance sheet of Peyto Energy Trust (the "Trust") as at December 31, 2006 and 2005 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, 2006 and 2005 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
Chartered Accountants

Calgary, Alberta
February 23, 2007

Member of
Deloitte Touche Tohmatsu

Peyto Energy Trust

Consolidated Balance Sheets

($000)

	December 31, 2006 $	December 31, 2005 $
Assets		
Current		
Cash	**10,806**	-
Accounts receivable	**53,418**	82,793
Due from private placements *(Note 6)*	**5,042**	27,450
Prepaid expenses and deposits	**2,681**	1,796
	71,947	112,039
Property, plant and equipment *(Note 3)*	**1,064,753**	832,887
	1,136,700	944,926
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	**70,836**	208,394
Cash distributions payable	**14,735**	11,530
Provision for future performance based compensation *(Note 10)*	**-**	8,748
	85,571	228,672
Long-term debt *(Note 4)*	**420,000**	180,000
Provision for future performance based compensation *(Note 10)*	**-**	1,401
Asset retirement obligations *(Note 5)*	**5,767**	4,729
Future income taxes *(Note 11)*	**135,650**	108,293
	561,417	294,423
Unitholders' equity		
Unitholders' capital *(Note 6)*	**398,434**	328,736
Units to be issued *(Note 6)*	**5,042**	28,332
Accumulated earnings	**86,236**	64,763
	489,712	421,831
	1,136,700	944,926

See accompanying notes

On behalf of the Board:

(signed) *"Michael MacBean"*
Director

(signed) *"Darren Gee"*
Director

Peyto Energy Trust

Consolidated Statements of Earnings and Accumulated Earnings

($000 except per unit amounts)

For the years ended December 31,

	2006	2005
	$	$
Revenue		
Petroleum and natural gas sales, net	**350,562**	324,893
Expenses		
Operating *(Note 8)*	**18,046**	12,546
Transportation	**4,856**	5,520
General and administrative*(Note 9)*	**3,966**	680
Performance based compensation *(Note 10)*	**12,311**	57,847
Future performance based compensation *(Note10)*	**(10,149)**	(18,271)
Interest on long term debt	**18,011**	8,702
Depletion, depreciation and accretion *(Note 3 and 5)*	**81,098**	58,208
	128,139	125,232
Earnings before taxes	**222,423**	199,661
Taxes		
Future income tax expense *(Note 11)*	**27,357**	37,618
Capital tax expense	**(162)**	475
	27,195	38,092
Net earnings for the year	**195,228**	161,568
Accumulated earnings, beginning of year	**64,763**	39,843
Distributions *(Note 7)*	**(173,755)**	(136,648)
Accumulated earnings, end of year	**86,236**	64,763
Earnings per unit *(Note 6)*		
Basic	**1.86**	1.64
Diluted	**1.86**	1.64

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Cash Flows

($000)

For the years ended December 31,

	2006	2005
	$	$
Cash provided by (used in)		
Operating Activities		
Net earnings for the year	**195,228**	161,568
Items not requiring cash:		
Future performance based compensation	**(10,149)**	(18,271)
Future income tax expense	**27,357**	37,618
Depletion, depreciation and accretion	**81,098**	58,208
Change in non-cash working capital related to operating activities *(Note 13)*	**(37,489)**	35,777
	256,045	274,900
Financing Activities		
Issue of trust units, net of costs	**30,857**	181,508
Cash distributions paid (net of DRIP)	**(158,204)**	(127,094)
Increase in bank debt	**240,000**	-
Change in non-cash working capital related to financing activities *(Note 13)*	**25,613**	2,092
	138,266	56,506
Investing Activities		
Additions to property, plant and equipment	**(311,926)**	(358,453)
Change in non-cash working capital related to investing activities *(Note 13)*	**(71,579)**	27,047
	(383,505)	(331,406)
Net increase (decrease) in cash	**10,806**	-
Cash, beginning of year	**-**	-
Cash, end of year	**10,806**	-

See accompanying notes

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 ("ceiling test"). 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 properties is not determined 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.

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

($000)	**2006** $	2005 $
Property, plant and equipment	**1,288,616**	976,005
Accumulated depletion and depreciation	**(223,863)**	(143,118)
	1,064,753	832,887

At December 31, 2006 costs of $38,939,577 (December 31, 2005 - $33,617,224) related to undeveloped land have been excluded from the depletion and depreciation calculation.

The Trust performed a ceiling test calculation at December 31, 2006 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, 2006 using the following independent engineering consultant's forecasted prices:

	2007	**2008**	**2009**	**2010**	**2011**	**Thereafter (2)**
Edmonton Ref Price ($CDN/bbl)(1)	**68.58**	**67.40**	**67.37**	**65.04**	**62.71**	**+2%**
AECO ($CDN/mmbtu)	**7.33**	**7.91**	**7.89**	**7.87**	**8.02**	**+2%**

(1) Future prices incorporated a $0.87 US/CDN exchange rate.
(2) Percentage change of 2.0% represents the change in future prices each year after 2011 to the end of the reserve life.

4. Long-Term Debt

The Trust has a syndicated $450 million extendible revolving credit facility with a stated term date of May 7, 2007. The facility is made up of a $20 million working capital sub-tranche and a $430 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 earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) 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 2006 was 5.0% (2005 – 4.0%).

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 $5.8 million as at December 31, 2006 (2005 - $4.7 million) based on a total future liability of $23.1 million (2005 - $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:

($000)	**2006** **$**	2005 $
Carrying amount, beginning of year	**4,729**	3,329
Increase in liabilities during the year	**686**	1,129
Settlement of liabilities during the year	**-**	-
Accretion expense	**352**	271
Carrying amount, end of year	**5,767**	4,729

6. Unitholders' Capital

Authorized: Unlimited number of voting trust units

Issued and Outstanding Trust Units (no par value) ($000)	**Number of Units**	**Amount $**
Balance, December 31, 2004	47,725,272	138,953
Trust units issued by private placement	670,000	31,586
Trust unit issue costs	-	(103)
Trust units issued pursuant to DRIP	28,645	1,356
Trust units issued pursuant to 2 for 1 split	48,423,917	-
Trust units issued by public offering	5,000,000	152,750
Trust unit issue costs	-	(8,054)
Trust units issued pursuant to DRIP	279,561	7,448
Trust units issued pursuant to OTUPP	206,452	4,800
Balance, December 31, 2005	102,333,847	328,736
Trust units issued by private placement	1,393,940	34,378
Trust units issued pursuant to DRIP	690,387	16,301
Trust units issued pursuant to OTUPP	833,220	19,019
Balance, December 31, 2006	**105,251,394**	**398,434**

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. Both the DRIP and OTUPP were suspended August 31, 2006.

Units to be Issued

On December 31, 2006 the Trust completed a private placement of 285,190 trust units to employees and consultants for net proceeds of $5,042,159 (priced using the weighted average price for the last 5 trading days of December). These trust units were issued on January 8, 2007. 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.

Per Unit Amounts

Earnings per unit have been calculated based upon the weighted average number of units outstanding during the year of 104,554,325 (2005 – 98,576,640). There are no dilutive instruments outstanding.

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.

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. The Board of Directors 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 $173.8 million (2005 - $136.7 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit
January 2006	January 31, 2006	February 15, 2006	$0.12
February 2006	February 28, 2006	March 15, 2006	$0.14
March 2006	March 31, 2006	April 13, 2006	$0.14
April 2006	April 30, 2006	May 15, 2006	$0.14
May 2006	May 31, 2006	June 15, 2006	$0.14
June 2006	June 30, 2006	July 14, 2006	$0.14
July 2006	July 31, 2006	August 15, 2006	$0.14
August 2006	August 31, 2006	September 15, 2006	$0.14
September 2006	September 30, 2006	October 13, 2006	$0.14
October 2006	October 31, 2006	November 15, 2006	$0.14
November 2006	November 30, 2006	December 15, 2006	$0.14
December 2006	December 31, 2006	January 15, 2007	$0.14

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.

($000)	**2006** **$**	2005 $
Field expenses	**25,765**	17,609
Processing and gathering income	**(7,719)**	(5,063)
Total operating costs	**18,046**	12,546

9. General and Administrative Expenses

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

($000)	**2006** **$**	2005 $
General & Administrative expenses	**9,397**	6,434
Overhead recoveries	**(5,431)**	(5,754)
Net General & Administravtive expenses	**3,966**	680

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%.

($millions except unit values)	**2006**	**2005**	**Change**
Net present value of proved producing reserves @ 8% based on constant Paddock Lindstrom 2007 price forecast	1,728.6	1,575.9	
Net debt before performance based compensation	(426.4)	(287.9)	
2006 distributions	-	(173.8)	
Net value	1,302.2	1,114.2	188.0
Equity adjustment factor*			81%
Equity adjusted increase in value			152.3
2006 reserve value based compensation @ 3%			$4.6

*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 2006 market based component was based on 1.5 million vested rights at an average grant price of $18.77, average cumulative distributions of $3.86 and the five day weighted average closing price of $17.68 (2005 – 2.0 million rights, average grant price of $10.82, average cumulative distributions of $2.18 per unit and five day weighted average closing price of $25.38). In 2006, 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:

($000)	**2006** **$**	**2005** $
Market based compensation	**8,491**	45,045
Reserve value based compensation	**4,570**	12,802
Recovery of prior year unpaid reserve bonus	**(750)**	-
Total	**12,311**	57,847

For the market based component, compensation costs as at December 31, 2006 related to 2.7 million non-vested rights with an average grant price of $24.78 were nil (2005 - $21.7 million).

11. Future Income Taxes

($000)	**2006** **$**	**2005** $
Earnings before income taxes	**222,423**	199,661
Statutory income tax rate	**36.75%**	37.62%
Expected income taxes	**81,740**	75,112
Increase (decrease) in income taxes from:		
Non-deductible crown charges	**10,328**	24,372
Resource allowance	**(11,812)**	(21,706)
Corporate income tax rate change	**(2,397)**	(371)

Attributed Canadian Royalty Income (ACRI)	**-**	(1,023)
Income attributed to the trust	**(50,823)**	(38,424)
Change in valuation allowance for share issue costs	**1,000**	(994)
Other	**(679)**	651
Future income tax expense	**27,357**	37,618

The net future income tax liability is comprised of:

	2006 **$**	2005 $
Differences between tax base and reported amounts for depreciable assets	**137,322**	112,789
Accrued expenditures	**-**	(2,859)
Provision for asset retirement obligation	**(1,672)**	(1,637)
	135,650	108,293

At December 31, 2006 the Trust has tax pools of approximately $670.8 million (December 31, 2005 - $582.4 million) available for deduction against future income. Peyto Energy Trust has approximately $7.7 million in unrecognized future income tax assets available to reduce future taxable income.

Proposed Tax Legislation
On October 31, 2006, the Minister of Finance announced its proposal to amend the Income Tax Act (Canada) to apply a Distribution Tax on distributions from publicly-traded income trusts. Under the proposal, existing income trusts will be subject to the new measures commencing in their 2011 taxation year, following a four-year grace period. The Minister of Finance has issued a Notice of Ways and Means Motion to Amend the Income Tax Act, but it is not known at this time if or when the proposal will be enacted by Parliament. In simplified terms, under the proposed tax plan, income distributions will first be taxed at the trust level at a special rate estimated to be 31.5%. Income distributions to individual unitholders will then be treated as dividends from a Canadian corporation and eligible for the dividend tax credit. Income distributions to corporations resident in Canada will be eligible for full deduction as tax free intercorporate dividends. Tax-deferred accounts (RRSPs, RRIFs and Pension Plans) will continue to pay no tax on distributions. Non-resident unitholders will be taxed on distributions at the non-resident withholding tax rate for dividends. The net impact on Canadian taxable investors is expected to be minimal because they can take advantage of the dividend tax credit. However, as a result of the 31.5% Distribution Tax at the trust level, distributions to tax-deferred accounts will be reduced by approximately 31.5%, and distributions to non-residents will be reduced by approximately 26.5%.

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, 2006 is as follows:

Crude Oil Period Hedged	**Type**	**Daily Volume**	**Weighted Average Price (CAD)**
January 1 to March 31, 2007	Fixed price	200 bbl	$82.82/bbl
January 1 to March 31, 2007	Fixed price	200 bbl	$87.35/bbl
January 1 to March 31, 2007	Fixed price	200 bbl	$88.00/bbl
April 1 to June 30, 2007	Fixed price	200 bbl	$82.39/bbl
April 1 to June 30, 2007	Fixed price	200 bbl	$87.10/bbl
April 1 to June 30, 2007	Fixed price	200 bbl	$88.05/bbl
July 1 to September 30, 2007	Fixed price	200 bbl	$87.61/bbl
July 1 to September 30, 2007	Fixed price	200 bbl	$88.20/bbl

Natural Gas Period Hedged	Type	Daily Volume	Weighted Average Price (CAD)
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
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.65/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$10.25/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	$8.65/GJ
Nov. 1, 2006 to March 31, 2007	Fixed price	5,000 GJ	$9.23/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$8.60/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.50/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.25/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.51/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.50/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.60/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.60/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.80/GJ
April 1, 2007 to March 31, 2008	Fixed price	5,000 GJ	$8.90/GJ

As at December 31, 2006, the Trust had committed to the future sale of 145,400 barrels of crude oil at an average price of $86.45 per barrel and 16,235,000 gigajoules (GJ) of natural gas at an average price of $8.54 per GJ or $9.99 per mcf based on the historical heating value of Peyto's natural gas. These contracts will generate revenue totaling $151.2 million. Based on the market's estimate of the future commodity prices as at December 31, 2006 the fair value of these contracts would be $117.3 million. Had these contracts been closed on December 31, 2006, the Trust would have realized a gain in the amount of $33.9 million.

Subsequent to December 31, 2006 the Trust entered into the following contracts:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.50/GJ
April 1 to October 31, 2007	Fixed price	5,000 GJ	$7.70/GJ
April 1, 2007 to March 31, 2008	Fixed price	5,000 GJ	$8.35/GJ

Crude Oil Period Hedged	Type	Daily Volume	Weighted Average Price (CAD)
July 1 to September 30, 2007	Fixed price	200 bbl	$77.12/bbl
October 1 to December 31, 2007	Fixed price	200 bbl	$77.51/bbl
January 1 to March 31, 2008	Fixed price	200 bbl	$78.55/bbl

Fair Values of Financial Assets and Liabilities

The Trust's financial instruments include cash, accounts receivable, due from private placement deposits, current liabilities, provision for future market performance based compensation and long term debt. At December 31, 2006, the carrying value of cash, accounts receivable, due from private placement deposits, 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, 2006, approximately 41% was due from one company (December 31, 2005 – 42%). Of the Trust’s revenue for the year ended December 31, 2006, approximately 59% was received from two companies (December 31, 2005 – 62%).

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 due to the floating rate nature of the interest expense on its revolving demand facility.

13. Supplemental Cash Flow Information

Changes in non-cash working capital balances

($000)	**2006** **$**	2005 $
Accounts receivable	**29,376**	(23,801)
Due from private placement	**22,408**	(370)
Prepaid expenses and deposits	**(886)**	3,467
Accounts payable and accrued liabilities	**(137,448)**	83,531
Capital taxes payable	**(110)**	(373)
Cash distributions payable	**3,205**	2,462
	(83,455)	64,916
Attributable to financing activities	**25,613**	2,092
Attributable to investing activities	**(71,579)**	27,047
Attributable to operating activities	**(37,489)**	35,777

	2006 **$**	2005 $
Cash interest paid during the year	**18,011**	8,702
Cash taxes paid during the year	**-**	848

14. Contingencies and Commitments

a) Contingent Liability

From time to time, Peyto is the subject of litigation arising out of its day-to-day operations. Damages claimed pursuant to such litigation, including the litigation discussed below, may be material or may be indeterminate and the outcome of such litigation may materially impact Peyto's financial position or results of operations in the period of settlement. While Peyto assesses the merits of each lawsuit and defends itself accordingly, Peyto may be required to incur significant expenses or devote significant resources to defending itself against such litigation. These claims are not currently expected to have a material impact on Peyto's financial position or results of operations. Peyto has been named in a Statement of Claim issued by Canadian Natural Resources Limited and affiliates ("CNRL"), claiming $13 million in damages for alleged breaches of duty as operator of jointly owned properties, and an interim and permanent injunction to prevent Peyto from proceeding with the completion of a well on those properties. CNRL alleges that Peyto failed to take proper steps as operator of a joint well (the "Well") on lands that offset 100% Peyto owned lands. Peyto has filed a Statement of Defense defending the allegations set forth in the Statement of Claim. The injunction claimed by CNRL was to prevent Peyto from completing the Well at a target location which had been agreed upon by both parties. Although claimed in the Statement of Claim, CNRL did not apply for an interim injunction, and Peyto completed the Well as planned, but no commercial production was obtained. Affidavits of Records were filed in July, 2006 but CNR had taken no steps to move the matter forward until February 14, 2007 when it proposed to amend its Statement of Claim to add a subsidiary as an additional Plaintiff and to particularize further its allegations. Accordingly, it remains to be seen whether CNRL will proceed with the action. If the action goes ahead, Peyto intends to defend itself vigorously. Although the outcome of this matter is not determinable at this time, Peyto believes that this claim will not have a material adverse effect on Peyto's financial position or results of operations.

b) Commitments

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

($000)	$
2007	953
2008	1,097
2009	1,097
2010	1,097
2011	1,097
	5,341

15. Related Party Transactions

During the period ended March 31, 2006, the Trust participated in a joint venture capital project with a company whose director was also a Peyto director until May 16, 2006. The Trust’s participation in this joint venture amounted to $620,218. Costs associated with this joint venture capital project were billed and paid in accordance with normal business operations.

An officer of the Trust is a partner of a law firm that provides legal services to the Trust. The fees charged are based on standard rates and time spent on matters pertaining to the Trust and its subsidiaries. For the year ended December 31, 2006, legal fees totaled $695,563 (2005 - $522,529).

Peyto Exploration & Development Corp. Information

Officers

Darren Gee
President and Chief Executive Officer

Scott Robinson
Executive Vice President and Chief Operating Officer

Ken Veres
Vice-President, Exploration

Glenn Booth
Vice President, Land

Kathy Turgeon
Vice President, Finance

Stephen Chetner
Corporate Secretary

Directors
Ian Mottershead, Chairman
Rick Braund
Don Gray
Brian Davis
John Boyd
Michael MacBean
Darren Gee
Gregory Fletcher

Auditors
Deloitte & Touche LLP

Solicitors
Burnet, Duckworth & Palmer LLP

Bankers
Bank of Montreal
Union Bank of California
Royal Bank of Canada
BNP Paribas
Société Générale
ATB Financial

Transfer Agent
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