PEYTO

Energy Trust

2009

Annual Report

Chairman's Message

Another year is now in the books, and with its passing we mark our eleventh full year in business. And what a profitable eleven years it has been. Peyto is in many respects an unparalleled success story in the Canadian energy industry. Even as the team has evolved and the breadth of our operations have grown, our entrepreneurial culture and business model have remained intact. Peyto's strength was demonstrated yet again over the past year in what was a difficult operating environment for natural gas producers. Our unitholders have every reason to be proud of our team's efforts and the results that have been generated.

The past year had its share of ups and downs, most of which were out of our control. As the year began, the state of the world economy presented the first challenge, rampant fear and tumbling markets. Thankfully, rational minds prevailed and markets began to work again. At the time of writing, Peyto has delivered a total return of 141% from the market low on March 11, 2009 and for our eleven year history, the total compound return is an unparalleled 66% per annum. In simple terms, $1,000 invested into Peyto back in 1998 would be worth $309,000 today. This is the best return of any public company in Canada over the same period and is a clear testimony to the success of our strategy, the quality of our assets and the ability of our people.

One of those people who contributed to Peyto's success was our former Chairman, Ian Mottershead, who retired in 2009. Ian and I first met when Peyto was only a few years old. At the time, Ian was in charge of the energy portfolio at one of Canada's largest private investment firms. Ian was known in the industry for his analytical and disciplined approach to investing. After our first meeting, I knew that Ian was a long-term investor who understood what made Peyto unique and compelling. Based on my dealings with analysts and portfolio managers across North America, Ian's approach was the exception, not the rule. Similarly, our focus on profitability, quality and low costs was the exception, not the rule. And that is what drew Ian to us and vice versa. In 2003, when Ian retired from the investment firm he helped build, I asked him to join the Peyto board. Although Ian had many larger companies seeking him as a director, he proudly accepted our offer. Ian served honourably as our Chairman for 6 years. I'm grateful to him for his stewardship and would like to thank him on behalf of all the directors and the employees for his invaluable contribution to the success of Peyto.

Halfway through 2009, we decided to shift gears and increase our capital spending. The timing was typical Peyto; counter-cyclical, accelerating our capital spending when service costs were low and gas prices were soft. It was at this time, that we began our shift from vertical to horizontal wellbores. The horizontal wellbore is half of the equation with the other half being the multiple hydraulic fractures used to stimulate the formation. We successfully drilled our first horizontal well in the second half of 2009 and have now drilled a total of 9 horizontal wells into three of our different resource plays, with impressive results.

It seems today that "resource play" and "horizontal well" have become the catch-all phrases for every promoter in the energy sector. Everyone has a resource play and is prepared to drill it up with horizontal wells. But as history has shown, in the energy industry there is usually a big gap between the story and reality. I'm proud to say that in Peyto's case, reality has always eclipsed the story. We believe strongly that this new approach coupled with our high quality assets and our team's ability to execute will play a significant role in building value for investors and generating superior returns in coming years. It is my pleasure to report today that after eleven very successful years, our assets have never looked better and our business has never been healthier.

Don T. Gray
Chairman of the Board

Report from the President

Peyto Energy Trust ("Peyto" or the "Trust") is pleased to present the operating and financial results for the fourth quarter and 2009 fiscal year. In a year of unprecedented financial turmoil, Peyto's industry leading cost structure, top quality assets and disciplined capital investment strategy delivered unitholders a 74% operating margin(1), 56% profit margin(2), 12% return on capital employed, and a 28% return on equity. The following summarizes Peyto's accomplishments in 2009:

- Invested $73 million of capital (net of $11.3 million in Drilling Royalty Credits) to find and develop 32 BCFe of new Proved Producing ("PP") reserves. All in FD&A costs for PP, Total Proved ("TP") and Proved plus Probable Additional ("P+P") reserves were $2.26/MCFe, $1.73/MCFe and $1.47/MCFe ($8.80/boe) including changes in future development capital.

- Grew Total Proved reserves to 893 BCFe and Proved plus Probable Additional reserves to 1.2 TCFe. The successful application of horizontal multi-stage fracture technology helped increase the Total Proved undeveloped reserves by 77% or 112 BCFe and the total P+P undeveloped reserves by 190% or 207 BCFe.

- Built 25 MMCFe/d (4,200 boe/d) of new production at a cost of $17,300/boe/d, down 48% from $33,100/boe/d in 2008.

- Maintained a low cost advantage with operating costs of $0.41/MCFe ($2.48/boe), similar to 2008 at $0.44/MCFe ($2.60/boe).

- Generated $203 million in Funds from Operations ($1.83/unit) and $153 million in Earnings ($1.38/unit).

- Reduced net debt by $52.8 million to $439.9 million, leaving $110 million of available capacity on bank lines of $550 million.

- Distributed $163.3 million to unitholders ($1.47/unit).

- Net Asset value or the NPV per unit, debt adjusted (discounted at 5%) of the Proved plus Probable Additional assets remained at $33/unit.

2009 in Review

Peyto has now completed its eleventh year of operations. In all respects it was a challenging year, as a continuous slide in natural gas prices (AECO daily average) which began in June of 2008 at $10.60/GJ, finally ended in August of 2009 at $2.61/GJ, a 75% drop. Natural gas prices then recovered to end the year at $5.23/GJ. Meanwhile, the global economies and capital markets of the world continued to struggle under the pressure of a recession. Unitholders of Peyto were able to take comfort in the Trust's low operating costs, strong hedge book and high quality, long reserve life assets to protect them during this volatile time. The Trust reduced distributions in response to these economic conditions and issued equity midway through the year. Both served to increase the financial flexibility of the business and allowed Peyto to capitalize on drilling opportunities prior to the recovery in both natural gas prices and industry activity. These opportunities, which included proving the application of horizontal multi-stage fracture technology on Peyto's Deep Basin tight gas resource plays, have served to significantly increase the amount of undeveloped potential in Peyto's asset base. Combined with short term Alberta royalty incentives, these future opportunities have some of the lowest natural gas supply costs in North America and should provide Peyto with growth in the future.

(1) Operating Margin is defined as Funds from Operations divided by Revenue before Royalties but including realized hedging gains (losses).
(2) Profit Margin is defined as Net Earnings for the year divided by Revenue before Royalties but including realized hedging gains (losses).
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). Natural gas liquids and oil volumes in barrel of oil (bbl) are converted to thousand cubic feet equivalent (mcfe) using a ratio of one (1) barrel of oil to six (6) thousand cubic feet. This could be misleading if used in isolation as it is based on an energy equivalency conversion method primarily applied at the burner tip and does not represent a value equivalency at the wellhead.

	3 Months Ended December 31		%	12 Months Ended December 31		%
	2009	2008	Change	**2009**	2008	Change
Operations						
Production						
Natural gas (mcf/d)	**95,467**	101,907	*(6)%*	**92,718**	100,384	*(8)%*
Oil & NGLs (bbl/d)	**3,222**	3,207	*0%*	**3,028**	3,265	*(7)%*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**114,798**	121,146	*(5)%*	**110,884**	119,975	*(8)%*
Barrels of oil equivalent (boe/d @ 6:1)	**19,133**	20,191	*(5)%*	**18,481**	19,996	*(8)%*
Product prices						
Natural gas ($/mcf)	**6.17**	7.99	*(23)%*	**6.44**	8.64	*(25)%*
Oil & NGLs ($/bbl)	**60.77**	46.16	*32%*	**50.18**	84.78	*(41)%*
Operating expenses ($/mcfe)	**0.38**	0.43	*(12)%*	**0.41**	0.44	*(6)%*
Transportation ($/mcfe)	**0.11**	0.10	*10%*	**0.11**	0.10	*10%*
Field netback ($/mcfe)	**5.64**	6.61	*(15)%*	**5.60**	7.18	*(22)%*
General & administrative expenses ($/mcfe)	**0.15**	0.11	*36%*	**0.18**	0.15	*20%*
Interest expense ($/mcfe)	**0.44**	0.45	*(2)%*	**0.41**	0.50	*(18)%*
Financial ($000, except per unit)						
Revenue	**72,218**	89,377	*(19)%*	**273,517**	418,885	*(35)%*
Royalties	**7,457**	9,765	*(24)%*	**25,671**	79,821	*(68)%*
Funds from operations	**53,302**	67,354	*(21)%*	**202,699**	286,907	*(29)%*
Funds from operations per unit	**0.46**	0.64	*(28)%*	**1.83**	2.71	*(32)%*
Total distributions	**41,371**	47,664	*(13)%*	**163,263**	186,731	*(13)%*
Total distributions per unit	**0.36**	0.45	*(20)%*	**1.47**	1.76	*(16)%*
Payout ratio	**78**	71	*10%*	**81**	65	*25%*
Earnings	**33,035**	50,711	*(35)%*	**152,774**	179,397	*(15)%*
Earnings per diluted unit	**0.28**	0.48	*(42)%*	**1.38**	1.69	*(18)%*
Capital expenditures	**26,307**	22,467	*17%*	**72,739**	139,324	*(48)%*
Weighted average trust units outstanding	**114,920,194**	105,920,194	*8%*	**110,555,810**	105,876,470	*4%*
As at December 31						
Net debt (before future compensation expense and unrealized hedging gains)				**439,860**	492,644	*11%*
Unitholders' equity				**612,483**	550,717	*11%*
Total assets				**1,254,113**	1,280,246	*(2)%*

Earnings	**33,035**	50,711		**152,774**	179,397	
Expenditures on site restoration and reclamation	**(51)**	-		**(51)**	-	
Items not requiring cash:						
Future income tax expense	**(5,065)**	1,778		**(31,444)**	32,111	
Depletion, depreciation and accretion	**19,037**	19,901		**73,298**	75,668	
Change in non-cash working capital	**(389)**	(24,276)		**4,111**	(39,055)	
Cash flows from operating activities	**46,567**	48,114		**198,688**	248,121	
Change in provision for performance based compensation	**1,266**	(5,036)		**3,042**	(269)	
Performance based compensation	**5,080**	-		**5,080**	-	
Change in non-cash working capital	**389**	24,276		**(4,111))**	39,055	
Funds from operations [(1)]	**53,302**	67,354		**202,699**	286,907	

(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. Management believes that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future distributions may vary.

Capital Expenditures

Net capital expenditures for 2009 totaled $72.7 million, a 48% decrease from 2008. Capital invested represented 36% of annual cash flow with over 75% of the investment occurring in the last half of the year as commodity prices began to improve. As is typical of Peyto's design, drill and build strategy, over 90% of the capital was invested in well related activity with $44.2 million in drilling, $22.7 million in completions, and $11.4 million in wellsite equipment, pipelines and facilities. The remaining $5.5 million was invested in new lands and seismic with 31 new sections of Deep Basin lands being added at $130/ac or at just 20% of 2008 prices. In total, $11.3 million of drilling royalty credit ("DRC") was earned, with $6.0 million claimed by the end of the year and $5.3 million yet to be claimed, reducing total capital by 13.5%.

The majority of the capital invested in 2009 was in the Greater Sundance core area where horizontal drilling technology was evaluated in three different formations; the Cardium, Notikewin and Wilrich. The remaining capital was spent on faulted Cardium development in the Ansell and Kakwa areas. The following table summarizes capital expenditures for the year.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2009**	2008	**2009**	2008
Land	**1,150**	730	**4,115**	2,106
Seismic	**644**	1,036	**1,470**	3,300
Drilling and Completions	**27,449**	15,786	**66,926**	114,302
Production Equipment, Facilities & Pipelines	**4,993**	4,915	**11,417**	19,583
Office Equipment	**13**	-	**153**	33
Total Capital Expenditures	**34,249**	22,467	**84,081**	139,324
Drilling Royalty Credit	**(7,942)**	-	**(11,342)**	-
Net Capital Expenditures	**26,307**	22,467	**72,739**	139,324

During the year, 24 gross (22.5 net) vertical and 5 gross (3.7 net) horizontal gas wells were drilled with 35 gross (32.5 net) new gas zones brought on production. Total capital per net well was $3.2 million in 2009 (prior to DRC), down from $3.4 million in 2008, despite the 5 horizontal wells which increase the average well cost.

Reserves

New reserves were again found and developed "by the drill bit" with the following table illustrating the change in reserve volumes and Net Present Value ("NPV") of future cash flow, discounted at 5%, before income tax using forecast pricing.

	As at December 31			
	2009	2008	% Change	% Change, debt adjusted per unit†
Reserves				
BCFe				
Proved Producing	**591.4**	599.8	*-1%*	*5%*
Total Proved	**893.1**	762.9	*17%*	*8%*
Proved + Probable Additional	**1,199.3**	998.3	*20%*	*28%*
Net Present Value ($million)				
Discounted at 5%				
Proved Producing	**$2,389**	$2,736	*-13%*	*-20%*
Total Proved	**$3,344**	$3,267	*2%*	*-4%*
Proved + Probable Additional	**$4,295**	$4,077	*5%*	*-1%*

†Per unit reserves are adjusted for changes in net debt by converting debt to equity using the Dec 31 unit price of $9.90 for 2008 and $14.06 for 2009. Net Present Values are adjusted for debt by subtracting net debt from the value prior to calculating per unit amounts.
Note: Based on the Paddock Lindstrom & Associates report effective December 31, 2009. The Paddock Lindstrom and Associates Ltd. price forecast is available at www.padlin.com. For more information on Peyto's reserves, refer to the Press Release dated February 10, 2010 announcing the 2009 Year End Reserve Report which is available on the 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 2010.

Value Creation/Reconciliation

In order to measure the success of the 2009 investments, it is necessary to quantify the amount of incremental value created during the year and compare that to the amount of capital invested. This exercise is undertaken to ensure the best use of the unitholders' capital on a go forward basis. At Peyto's request, and for the benefit of unitholders, the independent engineers have run last year's evaluation with this year's price forecast to remove the change in value attributable to both commodity prices and changing royalties. This approach isolates the value created by the Peyto team from the value created (or lost) by those changes outside of their control. Since the capital investments in 2009 were funded from a combination of cash flow, debt and equity, it is necessary to know the change in debt and the change in units outstanding to see if the change in value is truly accretive.

At year end 2009, the forecasted net debt had decreased by $52.8 million to $439.9 million while the number of units outstanding had increased by 9.2 million units to 115.1 million units (including the Dec. 31, 2009 private placement of 196,420 units issued on January 6, 2010). The change in debt includes all of the capital expenditures, net of Drilling Royalty Credits earned, and the total fixed and performance based compensation paid out during the year.

Based on this reconciliation of changes in BT NPV, the Peyto team was able to create $390 million of Proved Producing, $1,375 million of Total Proven, and $1,968 million of Proved plus Probable Additional undiscounted reserve value, with $73 million of capital investment. The ratio of capital expenditures to value creation is what Peyto refers to as the NPV recycle ratio, which is simply the undiscounted value addition, resulting from the capital program, divided by the capital investment. For 2009, the Proved Producing NPV recycle ratio is 5.4, compared with 2.1 for 2008.

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, 2009.

	Proved Producing			Total Proved			Proved + Probable Additional		
($millions) Discounted at	0%	5%	10%	0%	5%	10%	0%	5%	10%
Before Tax Net Present Value at Beginning of Year ($millions)									
Dec. 31, 2008 Evaluation using PLA Jan. 1, 2009 price forecast, less debt	**$4,781**	**$2,244**	**$1,332**	**$5,995**	**$2,775**	**$1,612**	**$8,069**	**$3,584**	**$2,037**
Debt Adjusted Per Unit Outstanding at Dec. 31, 2008 ($/unit)	$45.13	$21.18	$12.58	$56.60	$26.19	$15.22	$76.18	$33.84	$19.23
2009 sales (revenue less royalties and operating costs)	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**	**($227)**
Net Change due to price forecasts (using PLA Jan 1, 2010 price forecast)	**($729)**	**($390)**	**($275)**	**($934)**	**($500)**	**($349)**	**($1,213)**	**($626)**	**($428)**
Value Change due to discoveries (additions, extensions, transfers, revisions)	**$390**	**$322**	**$308**	**$1,375**	**$856**	**$650**	**$1,968**	**$1,124**	**$807**
Before Tax Net Present Value at End of Year ($millions)									
Dec. 31, 2009 Evaluation using PLA Jan. 1, 2010 price forecast, less debt	**$4,215**	**$1,949**	**$1,138**	**$6,210**	**$2,904**	**$1,687**	**$8,598**	**$3,856**	**$2,188**
Debt Adjusted Per Unit Outstanding at Dec. 31, 2009 ($/unit)	$36.62	$16.93	$9.89	$53.95	$25.23	$14.65	$74.69	$33.49	$19.01
Year over Year Change in Before Tax NPV/unit	**(19%)**	**(20%)**	**($21)**	**(5%)**	**(4%)**	**(4%)**	**(2%)**	**(1%)**	**(1%)**
Year over Year Change in Before Tax NPV/unit including Dist. ($1.47/unit)	**(16%)**	**(13%)**	**(10%)**	**(2%)**	**2%**	**6%**	**0%**	**3%**	**7%**

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. Peyto believes that the value analysis presented above is the best determination of profitability as it compares the value of what was created relative to what was invested, or what is termed, the 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 2009, the Proved Producing NPV recycle ratio was 5.4 times. This means for each dollar invested, the Peyto team was able to create 5.4 new dollars of Proved Producing reserve value. The average NPV Recycle Ratio over the last 5 years is 3.5 times for undiscounted future values or 2.2 times for future values discounted at 10%. The historic NPV recycle ratio is presented in the following table.

2009 Value Creation	**Dec 31, 2009**	Dec 31, 2008	Dec 31, 2007	Dec 31, 2006	Dec 31, 2005
NPV_0 Recycle Ratio					
Proved Producing	**5.4**	2.1	4.7	2.9	2.5
Total Proved	**18.9**	2.5	5.5	2.9	2.8
Proved + Probable Additional	**27.1**	2.2	3.8	3.8	3.2

- NPV_0 (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 (eg. Proved Producing ($390/$72.7) = 5.4).

The following table highlights some additional annual performance ratios, to be used for comparative purposes, but it is cautioned that they are incomplete and on their own do not measure investment success.

Performance Ratios	**Proved Producing**	**Total Proved**	**Proved + Probable Additional**
Finding, Development and Acquisition Costs ($/MCFe)			
2009 FD&A Cost (including the change in future development capital "FDC")	$2.26	$1.73	$1.47
2008 FD&A (incl. change in FDC)	$2.88	$3.17	$3.88
2007 FD&A (incl. change in FDC)	$2.11	$1.57	$1.56
3 year average (2007-2009)	$2.42	$2.16	$2.30
2009 Change in future development capital ($ millions)		$223	$282
Recycle Ratio (incl. change in FDC)			
Using 2009 field netback before hedging of $4.04/MCFe	1.8	2.3	2.7
Reserve Life Index (years)			
Q4 2009 average production – 114.8 MMCFe/d	14	21	29
Distribution Life Index (years)			
Q4 2009 annualized - $41.4 million	25	38	52
Reserve Replacement Ratio			
2009 production – 40.5 BCFe	0.8	4.2	6.0

- 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, including the change in undiscounted future development capital ("FDC"), by the change in the reserves, incorporating revisions and production, for the same period (eg. Total Proved ($72.7+$223.2)/(893.1-762.9+40.5) = $1.73).
- The Recycle Ratio is calculated by dividing the field netback per MCFe, before hedging, by the FD&A costs for the period (eg. Proved Producing (($5.60-$1.56)/$2.26=1.8). The recycle ratio is comparing the netback from existing reserves to the cost of finding new reserves and may not accurately indicate investment success unless the replacement reserves are of equivalent quality as the produced reserves.
- The reserve life index is calculated by dividing the reserves (in MMCFe) in each category by the annualized average production rate in MMCFe/year (eg. Proved Producing 591,438/(114.8x365) = 14).
- The distribution life index is calculated by dividing the debt adjusted undiscounted NPV by the Q4 annualized distribution (eg. Proved Producing ($4,655-$439.9 million)/(41.4x4) million/year = 25 years).
- The reserve replacement ratio is determined by dividing the yearly change in reserves before production by the actual annual production for the year (eg. Total Proved ((148,857-127,156+6,745)/6,745) = 4.2).

Finding, development and acquisition costs improved in 2009 as service cost reductions and increased recoveries combined to reduce the Proved Producing FD&A by 22% to $2.26/MCFe ($13.58/boe). The application of horizontal wells with multi-stage fracture stimulations to three of Peyto's Deep Basin formations resulted in the recognition of increased undeveloped reserves in both the Total Proved and Proved plus Probable Additional categories. The increase in undeveloped reserves served to reduce FD&A costs for Total Proved and P+P to $1.73/MCFe ($10.41/boe) and $1.47/MCFe ($8.80/boe) respectively (inclusive of changes in future development capital).

The cost to replace the Proved Producing reserves of $2.26/MCFe was 56% of the achieved 2009 field netback, before hedging effects, of $4.04/MCFe. This results in a recycle ratio of 1.8 times for Proved Producing, 2.3 times for Total Proved and 2.7 times for Proved plus Probable Additional.

The Total Proved and P+P reserve life index increased by 24% and 27% respectively to 21 and 29 years, primarily driven by the increases in undeveloped reserves. These increases occurred despite little change in Proved Producing reserve life and illustrates why Peyto believes the most accurate way to evaluate current reserve life is by dividing Proved Producing reserves by the most current average production rate. Using this method, Peyto's Proved Producing reserve life, based the on annualized Q4 2009 production rate, is 14 years. In Peyto's opinion, and for comparative purposes, the Proved Producing reserve life provides the best measure of sustainability.

The following table highlights the Trust's historical Reserve and Distribution Life Index.

	2003	2004	2005	2006	2007	2008	2009
PP RLI	10	9	11	12	13	14	14
PP DLI	14	17	22	23	24	25	25

Quarterly Review

Capital expenditures for the fourth quarter 2009 increased to $34.2 million (before $7.9 million in drilling royalty credits) up 52% from Q4 2008 and up 7% from Q3 2009 as the Trust continued to actively develop its Deep Basin resource plays. Drilling and completions accounted for $27.4 million while production equipment, pipelines and facilities accounted for $5.0 million. Land and seismic made up the balance of the capital expenditures at $1.8 million.

Daily production for Q4 2009 increased from 107 mmcfe/d in the previous quarter to 115 mmcfe/d, but was down from 121 mmcfe/d a year ago. Natural gas production of 95.5 mmcf/d and oil and natural gas liquids production of 3,222 bbls/d combined for the quarter over quarter increase. Natural gas prices, before hedging effects, also increased quarter over quarter from $3.31/mcf to $4.79/mcf, but were down from $7.30/mcf a year ago. Peyto's marketing strategy of layering in forward sales contributed for a gain of $1.38/mcf in the quarter, resulting in a realized gas price $6.17/mcf. Oil and natural gas liquids price averaged $60.77/bbl. Total revenue was down 19% from the previous year due primarily to the price of natural gas.

Fourth quarter 2009 operating costs of $0.38/mcfe were 13% lower than Q4 2008 primarily due to the optimization of methanol consumption in field operations. Transportation costs increased from $0.10/mcfe in Q4 2008 to $0.11/mcfe in Q4 2009 due to an increase in the pipeline tariffs. Royalties were 12% of sales, before hedging, in Q4 2009, effectively the same as in Q4 2008. Net of hedging effects, royalties were reduced to 10% of sales or $0.71/mcfe. G&A of $0.15/mcfe and interest expense of $0.44/mcfe combined with royalty, operating and transportation costs for a total cash cost of $1.79/mcfe, leaving a cash netback of $5.05/mcfe. This cash netback translates into a 74% operating margin.

Marketing

Peyto's marketing strategy of smoothing out short term fluctuations in the price of natural gas through future sales was again successful in 2009. A total realized hedging gain of $63.0 million for the year was the largest in the Trust's history. Since 2003, when the Trust began the practice of selling up to 50% of its total natural gas production for periods up to 24 months in advance, the cumulative realized gain has been $127 million. It is not expected that gains will always be realized. Over the long run, Peyto expects to break even on forward sales since this approach of layering in future sales will show hedging losses when short term prices climb and hedging gains when short term prices fall. In order to minimize counterparty risk, these marketing contracts are executed with financial institutions that are also members of Peyto's loan syndicate.

Details of the individual contracts are available in Management's Discussion and Analysis ("MD&A"). As of December 31, 2009, the Trust had committed to the future sale of 23,380,000 gigajoules (GJ) of natural gas at an average price of $6.03/GJ or $7.05/mcf. Had these contracts been closed on December 31, 2009, the Trust would have realized a gain in the amount of $9.9 million.

Activity Update

To date in 2010, Peyto has drilled 4 vertical and 5 horizontal wells (8.6 net or 96% average working interest). Currently there are two vertical rigs and two horizontal rigs active in the Trust's Deep Basin core areas. Horizontal wells are contributing 11% of the 125 mmcfe/d of current production and are expected to make up over 25% of the Trust's total production by the end of 2010. Minor infrastructure expansions in the form of pipeline looping and compressor installations are ongoing in order to minimize the backout effect of new production on existing volumes.

Spot natural gas prices in Alberta (AECO C Daily) dropped from $5.25/GJ in mid February 2010 to $4.25/GJ currently on expectations of an early end to winter and a ramping up of North American gas drilling. Peyto will remain flexible with respect to changes in natural gas prices and adjust the pace of its capital program accordingly.

Corporate Conversion

Peyto met with its advisors in 2009 and determined that, barring any unforeseen legislative changes and pending unitholder and regulatory approval, the conversion of the Trust into a corporate form will likely occur on December 31, 2010. The new corporate structure will continue to afford Peyto the ability to return profits from the success of the business to shareholders in the form of dividends. For the remainder of 2010, the Trust plans on maintaining distributions at $0.12/unit/month.

2010 Outlook

The future landscape for Peyto has changed significantly since this time last year. The world economies have stabilized and begun to recover with the emerging economies leading the way; especially in their demand for hydrocarbons. Here in North America, the glut of shale gas has literally been burned off by a cold winter, contributing to the recovery in natural gas prices. Evidence of the true supply cost of shale gas continues to emerge as does Western Canada's ability to compete. Meanwhile, Peyto's future looks even more encouraging with an increased inventory of resource opportunities, an enviable cost structure and a proven track record of profitable investing.

The trust anticipates, with its expected capital program of $175 to $200 million, that production growth will be achieved this year and strong total returns delivered to unitholders. Capital expenditures will continue to be funded from a combination of cashflow after distributions, working capital, equity, and bank lines.

Annual General Meeting

The Trust's Annual General Meeting of Unitholders is scheduled for 3:00 p.m. on Wednesday, May 19, 2010 at Livingston Place Conference Centre, +15 level, 222-3rd Avenue SW, Calgary, Alberta.

Unitholders are encouraged to visit the Peyto website at www.peyto.com where there is a wealth of information designed to inform and educate investors. A monthly President's Report can also be found on the website which follows the progress of the capital program and the ensuing production growth.

Darren Gee
President and CEO
March 10, 2010

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 (the "Trust" or "Peyto") for the years ended December 31, 2009 and 2008. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

This discussion provides management's analysis of Peyto's historical financial and operating results and provides estimates of Peyto's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant. Readers should be aware that historical results are not necessarily indicative of future performance. This MD&A was prepared using information that is current as of March 8, 2010. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com.

Certain information set forth in this MD&A, 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.

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

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, 2009, the total Proved plus Probable reserves were 1,199.3 billion cubic feet equivalent (199.9 million barrels of oil equivalent) as evaluated by the independent petroleum engineers. Production is weighted approximately 85% natural gas and 15% natural gas liquids and oil.

The Peyto model is designed to deliver a superior total return and, over time, growth in value, assets, production and income, all on a debt adjusted 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 payout ratio designed to efficiently fund a 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 eleven years indicate that these principles have been successfully implemented. This 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)	**2009**	2008	2007
Total revenue (before royalties)	**273,517**	418,885	404,033
Funds from operations	**202,699**	286,907	279,624
Per unit – basic and diluted	**1.83**	2.71	2.65
Earnings	**152,774**	179,397	208,884
Per unit – basic and diluted	**1.38**	1.69	1.98
Total assets	**1,254,113**	1,280,246	1,192,232
Total long-term debt	**435,000**	500,000	430,000
Cash distributions per unit	**1.47**	1.76	1.68

QUARTERLY FINANCIAL INFORMATION

	2009				2008			
($000 except per unit amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue (net of royalties)	**64,761**	56,353	56,598	70,133	79,612	86,607	87,682	85,164
Funds from operations	**53,302**	45,263	45,527	58,607	67,354	74,485	74,113	70,955
Per unit – basic and diluted	**0.46**	0.39	0.43	0.55	0.64	0.70	0.70	0.67
Earnings	**33,035**	26,976	29,189	63,574	50,711	64,834	31,412	32,440
Per unit – basic and diluted	**0.28**	0.24	0.28	0.60	0.48	0.61	0.30	0.31
Distributions	**41,371**	41,371	39,211	41,309	47,664	47,664	46,605	44,798
Per unit – diluted	**0.36**	0.36	0.37	0.39	0.45	0.45	0.44	0.42

RESULTS OF OPERATIONS

Production

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2009	2008	**2009**	2008
Natural gas (mmcf/d)	**95.5**	101.9	**92.7**	100.4
Oil & natural gas liquids (bbl/d)	**3,222**	3,207	**3,027**	3,265
Barrels of oil equivalent (boe/d)	**19,133**	20,191	**18,481**	19,996
Thousand cubic feet equivalent (mmcfe/d)	**114.8**	121.1	**110.9**	120.0

Natural gas production averaged 95.5 mmcf/d in the fourth quarter of 2009, 6% lower than the 101.9 mmcf/d reported for the same period in 2008. Oil and natural gas liquids production averaged 3,222 bbl/d, up from 3,207 bbl/d reported in the prior year. Production for the year decreased 8% from 120.0 mmcfe/d to 110.9 mmcfe/d (19,996 boe/d to 18,481 boe/d). The production decreases are attributable to Peyto's natural resource declines and reduced capital program.

Commodity Prices

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2009	2008	**2009**	2008
Natural gas ($/mcf)	**4.79**	7.30	**4.58**	8.87
Hedging – gas ($/mcf)	**1.38**	0.69	**1.86**	(0.23)
Natural gas – after hedging ($/mcf)	**6.17**	7.99	**6.44**	8.64
Oil and natural gas liquids($/bbl)	**60.77**	49.16	**50.18**	85.52
Hedging – oil ($/bbl)	**-**	-	**-**	(0.74)
Oil and natural gas liquids – after hedging ($/bbl)	**60.77**	49.16	**50.18**	84.78
Total Hedging ($/mcfe)	**1.14**	0.58	**1.56**	(0.21)
Total Hedging ($/boe)	**6.86**	3.49	**9.34**	(1.25)

Peyto's natural gas price, before hedging gains, averaged $4.79/mcf during the fourth quarter of 2009, a 34% decrease from $7.30/mcf reported for the equivalent period in 2008. Oil and natural gas liquids prices averaged $60.77/bbl, an increase of 24% from $49.16/bbl a year earlier. Average natural gas prices for the year were down 48% at $4.58/mcf while oil and natural gas liquids prices were down 41% at $50.18/bbl compared to 2008. Hedging activity accounted for $1.14/mcfe of Peyto's achieved price for the fourth quarter of 2009 and $1.56 of the annual price.

Revenue

($000)	Three Months ended Dec. 31 **2009**	2008	Twelve Months ended Dec. 31 **2009**	2008
Natural gas	**42,127**	68,396	**155,072**	325,840
Oil and natural gas liquids	**18,013**	14,501	**55,458**	102,206
Hedging gain (loss)	**12,078**	6,480	**62,987**	(9,161)
Total revenue	**72,218**	89,377	**273,517**	418,885

For the three months ended December 31, 2009, gross revenue decreased 19% to $72.2 million from $89.4 million for the equivalent period in 2008. Revenue for 2009 decreased 35% to $273.5 million. The decrease in revenue for the period was a result of decreased production volumes and lower commodity prices as detailed in the following table:

	Three Months ended Dec. 31			Twelve Months ended Dec. 31		
	2009	2008	**$million**	2009	2008	**$million**
Total Revenue, December 31, 2008			**89.4**			**418.9**
Revenue change due to:						
Natural gas						
Volume (mmcf)	8,783	9,375	**(4.7)**	33,842	36,740	**(25.0)**
Price ($/mcf)	$6.17	$7.99	**(16.0)**	$6.44	$8.64	**(74.5)**
Oil & NGL						
Volume (mbbl)	296	295	**0.1**	1,105	1,195	**(7.6)**
Price ($/bbl)	$60.77	$49.16	**3.4**	$50.18	$84.78	**(38.3)**
Total Revenue, December 31, 2009			**72.2**			**273.5**

Royalties

Royalties are paid to the owners of the mineral rights with whom leases are held, including the provincial government of Alberta. Alberta gas crown royalties are invoiced as 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.

($000 except per unit amounts)	Three Months ended Dec. 31 **2009**	2008	Twelve Months ended Dec. 31 **2009**	2008
Royalties	**7,457**	9,765	**25,671**	79,821
% of sales before hedging	**12**	12	**12**	19
% of sales after hedging	**10**	11	**9**	19
$/mcfe	**0.71**	0.88	**0.63**	1.82
$/boe	**4.24**	5.26	**3.81**	10.91

For the fourth quarter of 2009, royalties averaged $0.71/mcfe or approximately 10% of Peyto's total petroleum and natural gas sales. Royalties for the year were down 65% to $0.63/mcfe. The Alberta Government's New Royalty Framework ("NRF") was effective January 1, 2009 which resulted in an overall decrease in the Trust's royalties due to the low commodity price environment. This decrease was in line with management's expectations. Under the new royalty framework the crown royalty rate fluctuates with production rates and commodity prices. The royalty rate expressed as a%age 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. Substantially all of the Trust's production is in Alberta; consequently the NRF, including the Transitional Royalty Plan and the Energy Incentive Program, will have a significant impact on the Trust's royalty rates. In its 11 year history, Peyto has invested over $1.6 billion in capital projects and has found and developed gas reserves that have paid over $502 million in royalties.

On March 3, 2009, the Alberta Government announced a "Three Point Incentive Program" to stimulate new and continued economic activity. The program provides for the earning of certain royalty credits and royalty relief for wells drilled during the period April 1, 2009 to March 31, 2010. The key aspects of the program are (1) a drilling depth based credit applicable against corporate royalties and (2) a flat 5% royalty rate applicable for a one year period commencing with the on stream date for each new well drilled.

On June 25, 2009 the Alberta Government modified the "Three Point Incentive Program" in response to the continued lack of industry activity. The drilling depth based credit program was extended by one year from the original expiry date of March 31, 2010 until a new expiry date of March 31, 2011. In addition the one year flat 5% royalty rate benefit was also extended by one year. Originally, only new wells brought on stream after April 1, 2009 but before March 31, 2010 qualified for the one year flat 5% royalty rate. This program was also extended to March 31, 2011 such that new wells brought on stream before that date will qualify for the one year flat 5% royalty rate. As at December 31, 2009 $11.3 million in Alberta drilling credits have been earned and recognized as a reduction to capital spending.

The Trust continues to evaluate the amendments to the new royalty framework in order to determine the optimal elections that should be made.

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 production reduces operating expenses.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2009	2008	**2009**	2008
Operating costs ($000)				
Field expenses	**6,525**	7,789	**27,487**	30,391
Processing and gathering income	**(2,528)**	(2,950)	**(10,751)**	(11,349)
Total operating costs	**3,997**	4,839	**16,736**	19,042
$/mcfe	**0.38**	0.43	**0.41**	0.44
$/boe	**2.27**	2.60	**2.48**	2.60
Transportation	**1,172**	1,158	**4,541**	4,604
$/mcfe	**0.11**	0.10	**0.11**	0.10
$/boe	**0.67**	0.62	**0.67**	0.63

Operating costs were $4.0 million in the fourth quarter of 2009 compared to $4.8 million for the equivalent period in 2008. On a unit-of-production basis, operating costs averaged $0.38/mcfe in the fourth quarter of 2009 compared to $0.43/mcfe for the equivalent period in 2008. Transportation expense increased on a per mcfe basis due to an increase in pipeline tariffs effective January 1, 2009. Operating costs for the year averaged $0.67/mcfe in 2009 compared to $0.63/mcfe in 2008.

General and Administrative Expenses

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2009	2008	**2009**	2008
G&A expenses ($000)	**2,445**	2,274	**9,797**	10,227
Overhead recoveries	**(813)**	(1,033)	**(2,505)**	(3,572)
Net G&A expenses	**1,632**	1,241	**7,292**	6,655
$/mcfe	**0.15**	0.11	**0.18**	0.15
$/boe	**0.93**	0.67	**1.08**	0.91

General and administrative expenses before overhead recoveries for the year decreased primarily due to costs incurred in 2008 associated with the January 1, 2008 reorganization. For the fourth quarter, general and administrative expenses before overhead recoveries were up 7% over the same quarter of 2008. Capital overhead recoveries decreased 21% for the fourth quarter from $1.0 million to $0.8 million and 30% on an annual basis as a result of the reduced capital program in 2009.

Interest Expense

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2009	2008	**2009**	2008
Interest expense ($000)	**4,608**	5,020	**16,527**	21,857
$/mcfe	**0.44**	0.45	**0.41**	0.50
$/boe	**2.62**	2.70	**2.45**	2.99
Average interest rate	**4.2%**	4.0%	**3.5%**	4.8%

Fourth quarter 2009 interest expense was $4.6 million or $0.44/mcfe compared to $5.0 million or $0.45/mcfe for the equivalent period in 2008. 2009 interest expense was $16.5 million or $0.41/mcfe compared to $21.9 million or $0.50/mcfe a year earlier due to a reduction in the average interest rate and debt levels.

Netbacks

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($/mcfe)	**2009**	2008	**2009**	2008
Gross Sale Price	**5.70**	7.44	**5.19**	9.75
Hedging gain (loss)	**1.14**	0.58	**1.56**	(0.21)
Net Sale Price	**6.84**	8.02	**6.75**	9.54
Less: Royalties	**0.71**	0.88	**0.63**	1.82
Operating costs	**0.38**	0.43	**0.41**	0.44
Transportation	**0.11**	0.10	**0.11**	0.10
Field netback	**5.64**	6.61	**5.60**	7.18
General and administrative	**0.15**	0.11	**0.18**	0.15
Interest on long-term debt	**0.44**	0.45	**0.41**	0.50
Cash netback ($/mcfe)	**5.05**	6.05	**5.01**	6.53
Cash netback ($/boe)	**30.31**	36.26	**30.06**	39.20

Netbacks are a non-GAAP measure that represents the profit margin associated with the production and sale of petroleum and natural gas. Netbacks are per-unit of production measures used to assess the Trust's performance and efficiency. The primary factors that produce Peyto's strong netbacks and high margins are a low cost structure and the high heat content of its natural gas that results in higher commodity prices.

Depletion, Depreciation and Accretion

The 2009 provision for depletion, depreciation and accretion totaled $73.3 million compared to $75.7 million in 2008. On a unit-of-production basis, depletion, depreciation and accretion costs averaged $1.81/mcfe as compared to $1.72/mcfe in 2008.

Income Taxes

The current provision for future income tax recovery is $31.4 million (2008 – expense of $32.1 million). Peyto's trust structure is unique and was designed to provide for discretion at the operating trust level to distribute taxable income to the Trust. Resource pools are generated from the capital program, which are available to offset current and future income tax liabilities. Unitholders benefit as the Trust may use these resource pools to increase the tax free return of capital component of the cash distributions. As a result of the internal reorganization tht took place January 1, 2008, the tax rate applied to differences between the accounting basis and tax basis of the Trust's assets increased by approximately 3% (the difference between future corporate income tax rates and future tax rates applicable to trusts). Changes to the SIFT rules proposed in the 2008 Federal Budget have now been substantively enacted, resulting in the anticipated future income tax recovery.

Canada Revenue Agency ("CRA") has conducted an audit of restructuring costs claimed as a result of the trust conversion in 2003 that has resulted in the reclassification of $41.0 million dollars in employment related costs as eligible capital. In October, 2008, the Trust has received a notice of reassessment from the CRA and paid an amount of $7.3 million related to this audit. Based upon consultation with legal counsel, management's view is that CRA's position has no merit. A notice of appeal was filed May 19, 2009 and the appeal has been denied. Examinations for discovery are being scheduled.

On June 12, 2007, Bill C-52 (the "SIFT Rules") enacted the October 31, 2006 proposal to impose a new tax on distributions from flow-through entities, including publicly traded income trusts. Under the SIFT Rules, existing income trusts will be subject to the new measures commencing in their 2011 taxation year, following a four-year grace period. 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 the Federal Corporate rate and applicable provincial corporate rate. Income distributions to unitholders will then be treated as dividends from a Canadian corporation. Individual unitholders will be eligible for the dividend tax credit. Tax-deferred accounts (RRSPs, RRIFs, TFSAs and Pension Plans) will continue to pay no tax on distributions but will not be eligible to use the dividend tax credit. Non-resident unitholders will be taxed on distributions at the non-resident withholding tax rate for dividends. The net impact on individual Canadian taxable investors is expected to be minimal because they can take advantage of the dividend tax credit. However, as a result of the tax at the trust level, distributions to tax-deferred accounts and non-residents will be reduced.

Recent amendments to the Income Tax Act (Canada) facilitate the conversion of existing income trusts into corporations. In general, the amendments permit alternative transactions which allow a conversion to be tax deferred for both the unitholders and the income trust. Peyto has now met with its advisors and determined that, barring any unforeseen legislative changes and pending unitholder and regulatory approval, the conversion of the Trust into a corporate form will likely occur effective December 31, 2010. At the present time, Peyto believes that if structural or other similar changes are not made, the relative after-tax distribution amount in 2011 to taxable Canadian investors will remain approximately the same, however, will decline for both tax-deferred Canadian investors (RRSPs, RRIFs, TFSAs and pension plans, etc.) and foreign investors.

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 forward contracts with well established counterparties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices. In order to minimize counterparty risk, these marketing contracts are execute with financial institutions that are members of Peyto's loan syndicate. During 2009, a realized hedging gain of $63.0 million was recorded as compared to a hedging loss of $9.2 million in 2008. A summary of contracts outstanding in respect of the hedging activities are as follows:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1 , 2009 to March 31, 2010	Fixed Price	5,000 GJ	$7.65/GJ
April 1 , 2009 to March 31, 2010	Fixed Price	5,000 GJ	$6.90/GJ
November 1, 2009 to March 31, 2010	Fixed Price	5,000 GJ	$8.39/GJ
November 1, 2009 to March 31, 2010	Fixed Price	5,000 GJ	$8.35/GJ
November 1, 2009 to March 31, 2010	Fixed Price	5,000 GJ	$5.25/GJ
November 1 , 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.20/GJ
November 1 , 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.00/GJ
November 1, 2009 to March 31, 2011	Fixed Price	5,000 GJ	$6.20/GJ
November 1 , 2009 to March 31, 2011	Fixed price	5,000 GJ	$5.81/GJ
April 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$6.10/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.28/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.29/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.555/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$5.67/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$8.91/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$9.15/GJ
April 1 , 2011 to March 31, 2012	Fixed Price	5,000 GJ	$6.20/GJ

As at December 31, 2009, the Trust had committed to the future sale of 23,380,000 gigajoules (GJ) of natural gas at an average price of $6.03 per GJ or $7.05 per mcf. Had these contracts been closed on December 31, 2009, the Trust would have realized a gain in the amount of $9.9 million.

Subsequent to December 31, 2009 the Trust entered into the following contracts:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$5.50/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.70/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$5.82/GJ

Commodity Price Sensitivity

Peyto's earnings are largely determined by commodity prices for crude oil and natural gas including the US/Canadian dollar exchange rate. Volatility in these oil and gas prices can cause fluctuations in Peyto's earnings over which the Trust has no control. Low operating costs and a long reserve life reduce Peyto's sensitivity to changes in commodity prices.

Currency Risk Management

The Trust is exposed to fluctuations in the Canadian/US dollar exchange ratio since commodities are effectively priced in US dollars and converted to Canadian dollars. In the short term, this risk is mitigated indirectly as a result of a commodity hedging strategy that is conducted in a Canadian dollar currency. Over the long term, the Canadian dollar tends to rise as commodity prices rise. There is a similar correlation between oil and gas prices. Currently Peyto has not entered into any agreements to further manage its currency risks.

Interest Rate Risk Management
The Trust is exposed to interest rate risk in relation to interest expense on its revolving demand facility. Currently there are no agreements to manage this risk. At December 310, 2009, the increase or decrease in earnings for each 100 bps (1%) change in interest rate paid on the outstanding revolving demand loan amounts to approximately $4.6 million per annum.

LIQUIDITY AND CAPITAL RESOURCES

Funds from Operations
"Funds from operations" is a non-GAAP measure which represents cash flows from operating activities before changes in non-cash operating working capital and provision for future performance based compensation. Management considers funds from operations and per unit calculations of funds from operations to be key measures as they demonstrate the Trust's ability to generate the cash necessary to pay distributions, repay debt and make capital investments. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds from operations provides a useful measure of the Trust's ability to generate cash that is not subject to short-term movements in operating working capital. The most directly comparable GAAP measure is cash flows from operating activities. Funds from operations is reconciled to cash flows from operating activities below:

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2009**	2008	**2009**	2008
Cash flows from operating activities	**46,567**	48,114	**198,688**	248,121
Change in non-cash working capital	**389**	24,276	**(4,111)**	39,055
Change in provision for (recovery of) performance based compensation	**1,266**	(5,036)	**3,042**	(269)
Market and reserve value performance based compensation	**5,080**	-	**5,080**	-
Funds from operations	**53,302**	67,354	**202,699**	286,907
Funds from operations per unit	**0.46**	0.64	**1.83**	2.71

For the fourth quarter ended December 31, 2009, funds from operations totaled $53.3 million or $0.46 per unit, as compared to $67.4 million, or $0.64 per unit during the same quarter in 2008. Funds from operation for the year were down 29% to $203 million. Peyto's policy is to balance distributions to unitholders and funding for a capital program with cash flow and available bank lines. Earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond Peyto's control. Current volatility in commodity prices creates uncertainty as to the funds from operations and capital expenditure budget. Accordingly, results are assessed throughout the year and operational plans revised as necessary to reflect the most current information.

Revenues will be impacted by drilling success and production volumes as well as external factors such as the market prices for commodities and the exchange rate of the Canadian dollar relative to the US dollar.

Bank Debt
The Trust has a syndicated $550 million extendible revolving credit facility with a stated term date of April 30, 2010. The facility is made up of a $20 million working capital sub-tranche and a $530 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. The loan has therefore been classified as long-term on the balance sheet. The average borrowing rate for the three months ended December 31, 2009 was 4.2% (2008 – 4.0%).

Outstanding amounts on this facility bear interest at rates determined by the Trust's debt to cash flow ratio that range from prime plus 1.5% to prime plus 3.0% 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.

At December 31, 2009, $435 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, 2009, the working capital surplus was $1.8 million (including a non-cash current asset for an unrealized mark to market future hedging gain of $8.7 million).

Peyto believes funds generated from operations, together with borrowings under the credit facility will be sufficient to finance current operations and the planned capital expenditure program. The total amount of capital invested in 2009 will be driven by the number and quality of projects generated. Capital will only be invested if it meets the long term objectives of the Trust. The majority of the capital program will involve drilling, completion and tie-in of lower risk development gas wells. Peyto's rapidly scaleable business model has the flexibility to match planned capital expenditures to actual cash flow.

Net Debt

"Net debt" is a non-GAAP measure that is the sum of long-term debt and working capital excluding the current financial derivative instruments and current provision for future performance based compensation. It is used by management to analyze the financial position and leverage of the Trust. Net debt is reconciled below to long-term debt which is the most directly comparable GAAP measure:

($000)	**As at December 31, 2009**	As at December 31, 2008
Long-term debt	**435,000**	500,000
Current liabilities	**71,681**	64,742
Current assets	**(73,503)**	(96,817)
Financial derivative instruments	**8,683**	27,788
Prepaid capital	**-**	(3,069)
Provision for future performance based compensation	**(2,001)**	-
Net debt	**439,860**	492,644

Capital

Authorized: Unlimited number of voting trust units

Issued and Outstanding

Trust Units (no par value) ($000)	**Number of Units**	**Amount**
Balance, December 31, 2007	**105,712,364**	**406,301**
Trust units issued by private placement	207,830	3,932
Balance, December 31, 2008	**105,920,194**	**410,233**
Trust units issued	9,000,000	94,500
Trust units issuance costs (net of tax)	-	(4,326)
Balance, December 31, 2009	**114,920,194**	**500,407**

On June 26, 2009, Peyto closed an offering of 9,000,000 trust units at a price of $10.50 per trust unit, receiving net proceeds of $89.4 million (net of future income tax). On December 31, 2009, 114,920,194 trust units were outstanding (December 31, 2008 – 105,920,194).

Units to be Issued

On December 31, 2009 the Trust completed a private placement of 196,420 trust units to employees and consultants for net proceeds of $2.7 million ($13.89 per unit). These trust units were issued on January 6, 2010. Subsequent to the issuance of these units, 115,116,614 trust units were outstanding.

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 4% 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%. This methodology can generate interim results which vary significantly from the final compensation paid. Compensation expense of $0.5 million was recorded for the year ended December 31, 2009.

($millions except unit values)	2009	2008	Change
Net present value of proved producing reserves @ 8% based on constant Paddock Lindstrom 2010 price forecast	**1,379.0**	1,534	
Net debt before performance based compensation	**(437.5)**	(492.6)	
2009 distributions, G&A and interest	**187.1**		
Net value	**1,128.6**	1,041.4	**87.2**
Equity adjustment factor*			15%
Equity adjusted increase in value			**13.1**
2008 reserve value based compensation @ 4%			**0.5**

*Equity adjustment factor is calculated as the% increase in value per unit divided by the total% 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 6% 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. The 2009 market based component was based on 1.4 million vested rights at an average grant price of $17.46, average cumulative distributions of $4.91; 0.5 million vested rights at an average grant price of $9.53, average cumulative distributions of $1.47 and the five day weighted average closing price of $13.89.

The total amount expensed under these plans was as follows:

($000)	2009	2008
Market based compensation	**4,540**	-
Reserve value based compensation	**540**	-
Total	**5,080**	-

For the future market based component, compensation costs as at December 31, 2009 were $3 million, which related to 1.5 million non-vested rights with an average grant price of $16.53 and 1.0 million non-vested rights with an average grant price of $9.55.

Capital Expenditures

Net capital expenditures for the fourth quarter of 2009 totaled $26.3 million. Exploration and development related activity net of drilling royalty credits represented $19.5 million (74% of total), while expenditures on facilities, gathering systems and equipment totaled $5.0 million (19% of total) and land, seismic and acquisitions totaled $1.8 million (7% of total). Capital expenditures of $72.7 million for 2009 were 48% lower than 2008 capital expenditures. The following table summarizes capital expenditures for the year:

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2009**	2008	**2009**	2008
Land	**1,150**	730	**4,115**	2,106
Seismic	**644**	1,036	**1,470**	3,300
Drilling – Exploratory & Development	**27,449**	15,786	**66,926**	114,302
Production Equipment, Facilities & Pipelines	**4,993**	4,915	**11,417**	19,583
Drilling Royalty Credit	**(7,942)**	-	**(11,342)**	-
Office Equipment	**13**	-	**153**	33
Total Capital Expenditures	**26,307**	22,467	**72,739**	139,324

Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2009	2008	**2009**	2008
Funds from operations ($000)	**53,302**	67,354	**202,699**	286,907
Total distributions ($000)	**41,371**	47,664	**163,263**	186,731
Total distributions per unit ($)	**0.36**	0.45	**1.47**	1.76
Payout ratio (%)	**78**	71	**81**	65

Peyto's policy is to balance distributions to unitholders and funding for a capital program with cash flow and available bank lines. The Board of Directors is prepared to adjust the payout ratio levels (distributions declared divided by funds from operations) to achieve the desired distributions while maintaining 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.

Sustainability of Distributions

($000)	**Three months ended December 31, 2009**	**Year ended December 31, 2009**	Year ended December 31, 2008
Cash flows from operating activities	**46,567**	**198,688**	248,121
Earnings for the period	**33,035**	**152,774**	179,397
Distribution declared	**(41,371)**	**(163,263)**	(186,731)
Excess of cash flows from operating activities over distributions declared	**5,196**	**35,425**	61,390
(Shortfall) excess of earnings over distributions declared	**(8,336)**	**(10,489)**	(7,334)

Shortfalls of earnings over distributions paid are a result of non-cash charges such as depletion, depreciation and accretion which have no immediate impact on distribution sustainability.

Accumulated Earnings and Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2009**	2008	**2009**	2008
Opening accumulated earnings (before distributions)	**1,039,174**	868,724	**919,435**	740,038
Earnings for the period	**33,035**	50,711	**152,774**	179,397
Total accumulated earnings (before distributions)	**1,072,209**	919,435	**1,072,209**	919,435
Total accumulated distributions	**(972,460)**	(809,197)	**(972,460)**	(809,197)
Accumulated earnings (after distributions) per Balance Sheet	**99,749**	110,238	**99,749**	110,238

Since inception, Peyto has accumulated earnings of $1,072 million and distributed $972 million to unitholders.

Contractual Obligations

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

($000)	**December 31, 2009**
2010	1,036
2011	1,036
2012	1,036
2013	1,036
2014	1,036
	5,180

RELATED PARTY TRANSACTIONS

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, 2008, legal fees totaled $0.4 million.

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, TFSAs 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.

For 2009, the Trust paid distributions to the unitholders in the amount of $163.3 million (2008 - $186.7 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit (1)
January 2009	January 31, 2009	February 13, 2009	$0.15
February 2009	February 28, 2009	March 13, 2009	$0.12
March 2009	March 31, 2009	April 15, 2009	$0.12
April 2009	April 30, 2009	May 15, 2009	$0.12
May 2009	May 31, 2009	June 15, 2009	$0.12
June 2009	June 30, 2009	July 15, 2009	$0.12
July 2009	July 31, 2009	August 14, 2009	$0.12
August 2009	August 31, 2009	September 15, 2009	$0.12
September 2009	September 30, 2009	October 15, 2009	$0.12
October 2009	October 31, 2009	November 13, 2009	$0.12
November 2009	November 30, 2009	December 15, 2009	$0.12
December 2009	December 31, 2009	January 15, 2010	$0.12

(1) Distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.

US Taxpayers

US unitholders who receive cash distributions are subject to a 15% 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.

United States Proposed Changes to Qualifying Dividends

A bill was introduced into United States Congress on March 23, 2007 that could deny qualified dividend income treatment to the distributions made by the Trust to its U.S. unitholders. The bill is in the first step of the legislative process and it is uncertain whether it will eventually be passed into law in its current form. If the bill is passed in its current form, distributions received by U.S. unitholders would no longer qualify for the 15 per cent qualified dividend tax rate.

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

RISK MANAGEMENT

Investors who purchase units are participating in the net funds from operations from a portfolio of western Canadian 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.

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 received for 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 received for 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 natural gas through future sales. It is meant to be methodical and consistent and to avoid speculation.

Although Peyto's focus is on internally generated drilling programs, any acquisition of oil and natural gas assets depends on an assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of the units. Peyto employs experienced staff and performs appropriate levels of due diligence on the 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, Peyto employs experienced staff to evaluate and operate wells and utilize appropriate technology in operations. In addition, prudent work practices and procedures, safety programs and risk management principles, including insurance coverage protect the Trust against certain potential losses.

The value of Peyto's 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 oil and gas property investments. In order to mitigate this risk, 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.

Access to markets may be restricted at times by pipeline or processing capacity. These risks are minimized by controlling as much of the 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. Peyto has no control over the level of government intervention or taxation in the petroleum and natural gas industry. The Trust operates in such a manner to ensure, to the best of its knowledge that it is 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. Peyto has reviewed its environmental risks and is, to the best of its knowledge, in compliance with the appropriate environmental legislation and have determined that there is no current material impact on operations. Peyto employs environmentally responsible business operations, and looks to both Alberta provincial authorities and Canada's federal authorities for direction and regulation regarding environmental and climate change legislation.

Peyto is subject to financial market risk. In order to maintain substantial rates of growth, the Trust must continue reinvesting in, drilling for or acquiring petroleum and natural gas. The capital expenditure program is funded primarily through funds from operations, debt and, if appropriate, equity.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Trust is made known to the Trust's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Trust in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Trust's disclosure controls and procedures at the year end of the Trust and have concluded that the Trust's disclosure controls and procedures are effective at the financial period end of the Trust for the foregoing purposes.

Internal Control over Financial Reporting

The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal control over financial reporting to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Trust's internal control over financial reporting at the financial period end of the Trust and concluded that the Trust's internal control over financial reporting is effective, at the financial period end of the Trust, for the foregoing purpose.

The Trust is required to disclose herein any change in the Trust's internal control over financial reporting that occurred during the period ended December 31, 2009 that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting. No material changes in the Trust's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Trust's internal control over 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, 2009 were audited by independent petroleum engineers Paddock Lindstrom & Associates Ltd. Paddock has been evaluating reserves in this area and for Peyto for 11 consecutive years.

Depletion and Depreciation Estimate

The full cost method of accounting for petroleum and natural gas operations is followed 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 2010. 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.

Accounting Changes
Voluntary changes in accounting policy are made only if they result in financial statements which provide more reliable and relevant information. Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including these changes in earnings. When the Trust has not applied a new primary source of GAAP that has been issued, but is not effective, the Trust will disclose the fact along with information relevant to assessing the possible impact that application of the new primary source of GAAP will have on the financial statements in the period of initial application.

CHANGES IN ACCOUNTING POLICIES

Adoption of IFRS
In January 2006, the CICA Accounting Standards Board ("ASCB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by 2011. On February 13, 2008, The ASCB confirmed that the use of IFRS will be required in 2011 for publicly accountable profit-orientated enterprises. The Trust continues to assess the impact of the convergence of Canadian GAAP and IFRS. At this time, the Trust has appointed internal staff along with sponsorship from the senior leadership team to review the impact of converting to

IFRS on the accounting policies, information and computer systems, internal and disclosure controls, financial reporting in addition to the changes in the Trust's financial statements.
The Trust's auditors have and will be involved throughout the process to ensure policies are in accordance with these new standards.

The Trust has identified the main conversion risks, one of which is the transition from the full cost method of accounting, which the Trust currently uses to account for petroleum and natural gas operations, to something acceptable under IFRS. IFRS does not prescribe specific oil and gas accounting guidance other than for costs associated with the exploration and evaluation phase. The Trust currently follows full cost accounting as prescribed in Accounting Guideline ("AcG") 16, "Oil and Gas Accounting – Full Cost." Conversion to IFRS may have a significant impact on how the Trust accounts for costs pertaining to oil and gas activities, in particular those related to the pre-exploration and development phases. In addition, the level at which impairment tests are performed and the impairment testing methodology will differ under IFRS. The IFRS conversion will also result in other impacts, some of which may be significant in nature. Initial assessments of other impacts completed to date include future market based compensation, provisions and asset retirement obligations.

In July 2009 an amendment to IFRS 1 First Time Adoption of International Reporting Standards was issued that applies to oil and gas assets. The amendment allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and gas assets in the development or production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. Peyto is currently evaluating whether to use this exemption.

The Trust is currently finalizing its accounting policies. Once this is complete, an opening January 1, 2010 balance sheet in accordance with IFRS will be developed. The Trust will maintain both Canadian GAAP and IFRS compliant financial statements in 2010.

In addition, the Trust is monitoring the IASB's active projects and all changes to IFRS prior to January 1, 2011 will be incorporated as required.

At this time, the impact on the Trust's financial position and results of operations is not reasonably determinable or estimable for any IFRS conversion impacts identified to date.

Goodwill and Intangible Assets
On January 1, 2009, the Trust retrospectively adopted the Canadian Institute of Chartered Accountants (CICA) Section 3064, Goodwill and Intangible Assets issued by the AcSB. This section clarifies the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Adoption of this standard did not have an impact the Trust's results of operations or financial position.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities
Effective January 1, 2009, the Trust adopted the CICA Emerging Issues Committee (EIC) Abstract No.173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities (EIC 173). EIC 173 clarifies how an entity's own credit risk and that of the relevant counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. The new guidance did not have any impact on the financial position or earnings of the Trust.

Business Combinations
On January 1, 2009, the Trust prospectively adopted CICA Section 1582, Business Combinations issued by the AcSB. This section establishes principles and requirements of the acquisition method for business combinations and related disclosures. Adoption of this statement did not have an impact on the Trust's results of operations or financial position.

Consolidated Financial Statements and Non-Controlling Interests
On January 1, 2009, the Trust adopted CICA Sections 1601, Consolidated Financial Statements, and 1602, Non-Controlling Interests issued by the AcSB. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for non-controlling interests in consolidated financial statements subsequent to a business combination. Adoption of this statement did not have an impact on the Trust's results of operations or financial position.

Financial Instruments – Disclosures
On December 31, 2009 the Trust adopted CICA issued amendments to Handbook Section 3862, Financial Instruments – Disclosures. The amendments include enhanced disclosures relating to the fair value of financial instruments and the liquidity risk associated with financial instruments. Section 3862 now requires that all financial instruments measured at fair value be categorized into one of three hierarchy levels. Refer to Note 15 Financial Instruments and Risk Management for enhanced fair value disclosures and liquidity risk disclosures. The amendments are consistent with recent amendments to financial instrument disclosure standards in IFRS.

Financial Instruments – Recognition and Measurement
In July 2009, the CICA amended Section 3855, Financial Instruments – Recognition and Measurement, to prohibit the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured. Amendments to this section also include a revised definition of "loans and receivables" and, provided that certain conditions have been met, permits reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. These amendments are effective for the Trust on December 31, 2009.

ADDITIONAL INFORMATION

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

Quarterly information

	2009				2008
	Q4	Q3	Q2	Q1	Q4
Operations					
Production					
Natural gas (mcf/d)	**95,467**	89,259	90,191	95,998	101,907
Oil & NGLs (bbl/d)	**3,222**	2,916	2,950	3,022	3,207
Barrels of oil equivalent (boe/d @ 6:1)	**19,133**	17,792	17,982	19,021	20,191
Thousand cubic feet equivalent (mcfe/d @ 6:1)	**114,798**	106,755	107,892	114,128	121,146
Average product prices					
Natural gas ($/mcf)	**6.17**	5.74	6.14	7.68	7.99
Oil & natural gas liquids ($/bbl)	**60.77**	51.06	43.42	44.46	49.16
$/MCFE					
Average sale price ($/mcfe)	**6.84**	6.20	6.32	7.63	8.02
Average royalties paid ($/mcfe)	**0.71**	0.46	0.55	0.81	0.88
Average operating expenses ($/mcfe)	**0.38**	0.41	0.43	0.44	0.43
Average transportation costs ($/mcfe)	**0.11**	0.11	0.11	0.11	0.10
Field netback ($/mcfe)	**5.64**	5.22	5.23	6.27	6.61
General & administrative expense ($/mcfe)	**0.15**	0.15	0.19	0.22	0.11
Interest expense ($/mcfe)	**0.44**	0.46	0.39	0.35	0.45
Cash netback ($/mcfe)	**5.05**	4.61	4.65	5.70	6.05
Financial ($000 except per unit)					
Revenue	**72,218**	60,860	62,016	78,423	89,377
Royalties	**7,457**	4,507	5,417	8,290	9,765
Funds from operations	**53,302**	45,263	45,527	58,607	67,354
Funds from operations per unit	**0.46**	0.39	0.43	0.55	0.64
Total distributions	**41,371**	41,371	39,211	41,309	47,664
Total distributions per unit	**0.36**	0.36	0.37	0.39	0.45
Payout ratio	**78%**	91%	86%	70%	71%
Earnings	**33,035**	26,976	29,189	63,574	50,711
Earnings per diluted unit	**0.28**	0.24	0.28	0.60	0.48
Capital expenditures	**26,307**	28,725	4,671	13,036	22,467
Weighted average trust units outstanding	**114,920,194**	114,920,194	106,315,798	105,920,194	105,920,194

Deloitte.

Deloitte & Touche LLP
3000 Scotia Centre
700 Second Street S.W.
Calgary AB T2P 0S7
Canada

Tel: (403) 267-1700
Fax: (403) 264-2871
www.deloitte.ca

Auditors' Report

To the Unitholders of
Peyto Energy Trust:

We have audited the consolidated balance sheets of Peyto Energy Trust (the "Trust") as at December 31, 2009 and 2008 and the consolidated statements of earnings, comprehensive income, accumulated earnings and accumulated other comprehensive income 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, 2009 and 2008 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 19, 2010

Peyto Energy Trust

Consolidated Balance Sheets

($000)

	December 31, 2009	December 31, 2008
Assets		
Current		
Accounts receivable *(Note 5)*	58,305	65,662
Due from private placement *(Note 9)*	2,728	-
Financial derivative instruments *(Note 15)*	8,683	27,788
Prepaid expenses	3,787	3,367
	73,503	96,817
Financial derivative instruments *(Note 15)*	1,253	2,458
Prepaid capital	955	3,069
Property, plant and equipment *(Note 6)*	1,178,402	1,177,902
	1,180,610	1,183,429
	1,254,113	1,280,246
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	55,890	48,854
Cash distributions payable *(Note 10)*	13,790	15,888
Provision for future performance based compensation *(Note 13)*	2,001	-
	71,681	64,742
Long-term debt *(Note 7)*	435,000	500,000
Provision for future performance based compensation *(Note 13)*	1,041	-
Asset retirement obligations *(Note 8)*	10,487	9,479
Future income taxes *(Note 14)*	123,421	155,308
	569,949	664,787
Unitholders' equity		
Unitholders' capital *(Note 9)*	500,407	410,233
Units to be issued *(Note 9)*	2,728	-
Accumulated earnings *(Note 10)*	99,749	110,238
Accumulated other comprehensive income	9,599	30,246
	109,348	140,484
	612,483	550,717
	1,254,113	1,280,246

See accompanying notes

On behalf of the Board:

(signed) *"Michael MacBean"*
Director

(signed) *"Darren Gee"*
Director

Peyto Energy Trust

Consolidated Statements of Earnings

($000 except per unit amounts)

For the years ended December 31,

	2009	2008
Revenue		
Oil and gas sales	**210,530**	428,047
Realized gain (loss) on hedges *(Note 15)*	**62,987**	(9,161)
Royalties	**(25,671)**	(79,821)
Petroleum and natural gas sales, net	**247,846**	339,065
Expenses		
Operating *(Note 11)*	**16,736**	19,042
Transportation	**4,541**	4,604
General and administrative*(Note 12)*	**7,292**	6,655
Performance based compensation *(Note 13)*	**5,080**	-
Future performance based compensation *(Note 13)*	**3,042**	(269)
Interest on long term debt	**16,527**	21,857
Depletion, depreciation and accretion *(Notes 6 and 8)*	**73,298**	75,668
	126,516	127,557
Earnings before taxes	**121,330**	211,508
Taxes		
Future income tax (recovery) expense *(Note 14)*	**(31,444)**	32,111
Earnings for the year	**152,774**	179,397
Earnings per unit *(Note 9)*		
Basic and diluted	**1.38**	1.69

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Comprehensive Income

($000)

For the years ended December 31,

	2009	2008
Earnings for the year	**152,774**	179,397
Other comprehensive income (loss)		
Change in unrealized gain (loss) on cash flow hedges	**42,340**	15,966
Realized (gain) loss on cash flow hedges	**(62,987)**	9,161
Comprehensive Income	**132,127**	204,524

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Accumulated Earnings and Accumulated Other Comprehensive Income

($000)

For the years ended December 31,

	2009	2008
Accumulated earnings, beginning of year	**110,238**	117,572
Earnings for the year	**152,774**	179,397
Distributions *(Note 10)*	**(163,263)**	(186,731)
Accumulated earnings, end of year	**99,749**	110,238

Accumulated other comprehensive income, beginning of year	**30,246**	5,119
Other comprehensive income (loss)	**(20,647)**	25,127
Accumulated other comprehensive income, end of year	**9,599**	30,246

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Cash Flows

($000)

For the years ended December 31,

	2009	2008
	$	$
Cash provided by (used in)		
Operating Activities		
Earnings for the year	**152,774**	179,397
Items not requiring cash:		
Future income tax (recovery) expense	**(31,444)**	32,111
Depletion, depreciation and accretion	**73,298**	75,668
Expenditures on site restoration and reclamation *(Note 8)*	**(51)**	-
Change in non-cash working capital related to operating activities *(Note 17)*	**4,111**	(39,055)
	198,688	248,121
Financing Activities		
Issue of trust units	**94,500**	3,932
Issuance costs	**(5,106)**	-
Cash distributions paid	**(163,263)**	(186,731)
Increase (decrease) in bank debt	**(65,000)**	70,000
Change in non-cash working capital related to financing activities *(Note 17)*	**(2,098)**	1,088
	(140,967)	(111,711)
Investing Activities		
Additions to property, plant and equipment	**(70,624)**	(142,393)
Change in non-cash working capital related to investing activities *(Note 17)*	**12,903**	(14,564)
	(57,721)	(156,957)
Net increase (decrease) in cash	**-**	(20,547)
Cash, beginning of year	**-**	20,547
Cash, end of year	**-**	-

See accompanying notes

Peyto Energy Trust

Notes to Consolidated Financial Statements

December 31, 2009 and 2008

1. Nature of Operations

Peyto Energy Trust (the "Trust" or "Peyto") is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The beneficiaries of the Trust are the holders of the Trust units. 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, 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 consolidated 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 consolidated financial statements include the accounts of Peyto Energy Trust and its wholly owned subsidiaries, Peyto Exploration & Development Corp., Peyto Operating Trust, Peyto Energy Limited Partnership and Peyto Energy Administration Corp.

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 cost of unproved properties, less impairment, 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 cost of unproved properties, less impairment. The discounted 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. All 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 natural gas fixed price contracts, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are 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. For financial derivative contracts settling in future periods, a financial asset or liability is recognized in the balance sheet and measured at fair value, with changes in fair value recognized in other comprehensive 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 timely preparation of the consolidated financial statements in conformity with Canadian generally accepted accounting principles requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, asset retirement costs and obligations and amounts used for ceiling test and impairment calculations are based on estimates of gross proved reserves and future costs required to develop those reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and the related future cash flows are subject to measurement uncertainty, and the impact in the consolidated financial statements of future periods could be material.

The amount of compensation expense accrued for future performance-based compensation arrangements are subject to management’s best estimate of whether or not the performance criteria will be met and what the ultimate payout will be.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Trust and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Future income taxes
The Trust follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in earnings in the period that the change occurs.

Financial Instruments
All financial instruments must initially be recognized at fair value on the consolidated balance sheet. The Trust has classified each financial instrument into the following categories: "held for trading"; "loans & receivables"; and "other financial liabilities". Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held for trading financial instruments are recognized in earnings. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method. The Trust has made the following classifications:

Financial Assets & Liabilities	**Category**
Cash	Held for trading
Accounts Receivable	Loans & receivables
Due from Private Placement	Loans & receivables
Accounts Payable and Accrued Liabilities	Other Liabilities
Provision for Future Performance Based Compensation	Other Liabilities
Distributions Payable	Other Liabilities
Long Term Debt	Other Liabilities
Financial Derivative Instruments	Held for trading

Derivative Instruments and Risk Management
Derivative instruments are utilized by the Trust to manage market risk against volatility in commodity prices. The Trust's policy is not to utilize derivative instruments for speculative purposes. The Trust has chosen to designate its existing derivative instruments as cash flow hedges. The Trust assesses, on an ongoing basis, whether the derivatives that are used as cash flow hedges are highly effective in offsetting changes in cash flows of hedged items. All derivative instruments are recorded on the balance sheet at their fair value. The effective portion of the gains and losses is recorded in other comprehensive income until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the consolidated statement of earnings, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Any hedge ineffectiveness is immediately recognized in earnings. The fair values of forward contracts are based on forward market prices.

Embedded Derivatives
An embedded derivative is a component of a contract that causes some of the cash flows of the combined instrument to vary in a way similar to a stand-alone derivative. This causes some or all of the cash flows that otherwise would be required by the contract to be modified according to a specified variable, such as interest rate, financial instrument price, commodity price, foreign exchange rate, a credit rating or credit index, or other variables to be treated as a financial derivative. The Trust has no contracts containing embedded derivatives.

3. Changes in Accounting Policies

Goodwill and Intangible Assets
On January 1, 2009, the Trust retrospectively adopted the Canadian Institute of Chartered Accountants (CICA) Section 3064, Goodwill and Intangible Assets issued by the Accounting Standards Board ("AcSB"). This section clarifies the criteria for the recognition of assets, intangible assets and internally developed intangible assets. Adoption of this standard did not have an impact the Trust's results of operations or financial position.

Business Combinations
On January 1, 2009, the Trust prospectively adopted CICA Section 1582, Business Combinations issued by the AcSB. This section establishes principles and requirements of the acquisition method for business combinations and related disclosures. Adoption of this statement did not have an impact on the Trust's results of operations or financial position.

Consolidated Financial Statements and Non-Controlling Interests
On January 1, 2009, the Trust adopted CICA Sections 1601, Consolidated Financial Statements, and 1602, Non-Controlling Interests issued by the AcSB. Section 1601 establishes standards for the preparation of consolidated financial statements. Section 1602 provides guidance on accounting for non-controlling interests in consolidated financial statements subsequent to a business combination. Adoption of this statement did not have an impact on the Trust's results of operations or financial position.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities
Effective January 20, 2009, the Trust adopted the CICA Emerging Issues Committee (EIC) Abstract No.173, Credit Risk and the Fair Value of Financial Assets and Financial Liabilities (EIC 173). EIC 173 clarifies how an entity's own credit risk and that of the relevant counterparty should be taken into account in determining the fair value of financial assets and financial liabilities, including derivative instruments. Adoption of this statement did not have an impact on the Trust's results of operations or financial position.

Financial Instruments – Disclosures
In May 2009, the CICA amended Section 3862, Financial Instruments – Disclosures, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009.

Financial Instruments – Recognition and Measurement
In July 2009, the CICA amended Section 3855, Financial Instruments – Recognition and Measurement, to prohibit the reclassification of a financial asset out of the held-for-trading category when the fair value of the embedded derivative in a combined contract cannot be reasonably measured. Amendments to this section also include a revised definition of "loans and receivables" and, provided that certain conditions have been met, permits reclassification of financial assets from the held-for-trading and available-for-sale categories into the loans and receivables category. The amendments also provide one method of assessing impairment for all financial assets regardless of classification. These amendments are effective for the Trust on December 31, 2009.

4. Pending Accounting Pronouncements

International Financial Reporting Standards ("IFRS")
In January 2006, the CICA Accounting Standards Board ("ASCB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by 2011.

On February 13, 2008, The ASCB confirmed that the use of IFRS will be required in 2011 for publicly accountable profit-orientated enterprises.

5. Accounts Receivable

($000)	**2009**	2008
Accounts receivable – general	**51,150**	58,394
Accounts receivable – income taxes	**7,155**	7,268
	58,305	65,662

Canada Revenue Agency ("CRA") has conducted an audit of restructuring costs claimed as a result of the Trust conversion in 2003 that has resulted in the reclassification of $41.0 million dollars in employment related costs as eligible capital. In October, 2008, the Trust received a notice of reassessment from the CRA and paid an amount of $7.2 million related to this audit. Based upon consultation with legal counsel, Management's view is that CRA's position has no merit. A notice of appeal was filed May 19, 2009 and the appeal has been denied. Examinations for discovery are being scheduled.

6. **Property, Plant and Equipment**

($000)	**2009**	2008
Property, plant and equipment	**1,624,655**	1,551,789
Accumulated depletion and depreciation	**(446,253)**	(373,887)
	1,178,402	1,177,902

At December 31, 2009 costs of $26.6 million (December 31, 2008 - $36.8 million) related to undeveloped land have been excluded from the depletion and depreciation calculation.

The Trust performed a ceiling test calculation at December 31, 2009 resulting in the undiscounted cash flows from proved reserves plus the cost of unproved properties, less impairment, exceeding the carrying value of petroleum and natural gas assets. The impairment test was calculated at December 31, 2009 using the following independent engineering consultant's forecasted prices:

	2010	**2011**	**2012**	**2013**	**2014**	**Thereafter (1)**
Edmonton Ref Price ($CDN/bbl)	84.21	86.84	89.47	94.74	100.00	+2.0%
CDN/US Exchange rate	0.95	0.95	0.95	0.95	0.95	0.95
AECO ($CDN/mmbtu)	5.82	6.29	6.77	7.28	7.80	+2.3%

(1) Percentage change for the Edmonton Ref Price and the AECO Price of 2.0% and 2.3% respectively, represents the average change in future prices each year after 2014 to the end of the reserve life.

7. **Long-Term Debt**

The Trust has a syndicated $550 million extendible revolving credit facility with a stated term date of April 30, 2010. The facility is made up of a $20 million working capital sub-tranche and a $530 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 plus 1.50% to prime plus 3.00% 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 Trust is in compliance with all debt covenants. The average borrowing rate for 2009 was 3.5% (2008 – 4.8%).

8. **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 $10.5 million as at December 31, 2009 (2008 - $9.5 million) based on a total future liability of $36.0 million (2008 - $34.2 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)	**2009**	2008
Balance, December 31, 2008	**9,479**	6,766
Increase in liabilities relating to investing activities	**392**	1,697
Settlement of reclamation liabilities during the year	**(51)**	-
Accretion expense	**667**	1,016
Balance, December 31, 2009	**10,487**	9,479

9. **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, 2007	**105,712,364**	**406,301**
Trust units issued by private placement	207,830	3,932
Balance, December 31, 2008	**105,920,194**	**410,233**
Trust units issued by private placement	-	-
Trust units issued	9,000,000	94,500
Trust unit issuance costs (net of tax)	-	(4,326)
Balance, December 31, 2009	**114,920,194**	**500,407**

On June 26, 2009, Peyto closed an offering of 9,000,000 trust units at a price of $10.50 per trust unit, receiving net proceeds of $89.4 million.

Units to be Issued
On December 31, 2009 the Trust completed a private placement of 196,420 trust units to employees and consultants for net proceeds of $2,728,274 (priced using the weighted average price for the last 5 trading days of December). These trust units were issued on January 6, 2010.

Per Unit Amounts
Earnings per unit have been calculated based upon the weighted average number of units outstanding during the year of 110,555,810 (2008 - 105,876,470). 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.

Comprehensive Income
Comprehensive income consists of earnings and other comprehensive income ("OCI"). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge. "Accumulated other comprehensive income" is a equity category comprised of the cumulative amounts of OCI.

10. **Accumulated Cash Distributions**

During the year, the Trust paid distributions to the unitholders in the aggregate amount of $163.3 million (2008 - $186.7 million total) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit(1)
January 2009	January 31, 2009	February 13, 2009	$0.15
February 2009	February 29, 2009	March 13, 2009	$0.12
March 2009	March 31, 2009	April 15, 2009	$0.12
April 2009	April 30, 2009	May 15, 2009	$0.12
May 2009	May 31, 2009	June 15, 2009	$0.12
June 2009	June 30, 2009	July 15, 2009	$0.12
July 2009	July 31, 2009	August 14, 2009	$0.12
August 2009	August 31, 2009	September 15, 2009	$0.12

September 2009	September 30, 2009	October 15, 2009	$0.12
October 2009	October 31, 2009	November 14, 2009	$0.12
November 2009	November 30, 2009	December 15, 2009	$0.12
December 2009	December 31, 2009	January 15, 2010	$0.12

(1) Distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.

Accumulated Earnings and Distributions

($000)	**2009**	2008
Accumulated earnings, beginning of year	**919,435**	740,038
Earnings for the year	**152,774**	179,397
Total accumulated earnings	**1,072,209**	919,435
Total accumulated distributions	**(972,460)**	(809,197)
Accumulated earnings, end of year	**99,749**	110,238

11. **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)	**2009**	2008
Field expenses	**27,487**	30,391
Processing and gathering income	**(10,751)**	(11,349)
Total Operating expenses	**16,736**	19,042

12. **General and Administrative Expenses**

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

($000)	**2009**	2008
General and Administrative expenses	**9,797**	10,227
Overhead recoveries	**(2,505)**	(3,572)
Net General and administrative expenses	**7,292**	6,655

13. **Performance Based Compensation**

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

Reserve Based Component

The reserves value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity, distributions, general and administrative costs and interest, 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)	2009	2008	Change
Net present value of proved producing reserves @ 8% based on constant Paddock Lindstrom 2010 price forecast	**1,379.0**	1,534.0	
Net debt before performance based compensation	**(437.5)**	(492.6)	
2009 distributions, general and administration and interest expense	**187.1**		
Net value	**1,128.6**	1,041.4	**87.2**
Equity adjustment factor*			15%
Equity adjusted increase in value			**13.1**
2009 reserve value based compensation @ 4%			**0.5**

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

Market Based Component

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 6% 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. The 2009 market based component was based on 1.4 million vested rights at an average grant price of $17.46, average cumulative distributions of $4.91; 0.5 million vested rights at an average grant price of $9.53, average cumulative distributions of $1.47 and the five day weighted average closing price of $13.89 (2008 – 1.2 million rights, average grant price of $24.94, average cumulative distributions of $5. 10 per unit and five day weighted average closing price of $9.53).

The total amount expensed under these plans was as follows:

($000)	2009	2008
Market based compensation	**4,540**	-
Reserve value based compensation	**540**	-
Total	**5,080**	-

For the future market based component, compensation costs as at December 31, 2009 related to 1.5 million non-vested rights with an average grant price of $16.53 and 1.0 million non-vested rights with an average grant price of $9.55 were $3.0 million (2008 - 3.1 million non-vested rights with an average grant price of $17.04 were $nil).

14. Future Income Taxes

($000)	2009	2008
Earnings before income taxes	**121,330**	211,508
Statutory income tax rate	**29.00%**	32.50%
Expected income taxes	**35,186**	68,740
Increase (decrease) in income taxes from:		
Corporate income tax rate change	**(25,277)**	9,338
Income attributed to the trust	**(40,244)**	(45,516)
Change in valuation allowance for share issue costs	**(1,040)**	(480)
Other	**(69)**	29
Future income tax expense (recovery)	**(31,444)**	32,111

Differences between tax base and reported amounts for depreciable assets	**126,746**	157,962
Financial derivative asset	**337**	
Share issuance costs	**(781)**	-
Future performance based bonuses	**(260)**	-
Provision for asset retirement obligation	**(2,621)**	(2,654)
Future income taxes	**123,421**	155,308

At December 31, 2009 the Trust has tax pools of approximately $676.1 million (December 31, 2008 - $653.8 million) available for deduction against future income. The Trust has approximately $6.0 million (December 31, 2008 - $1.4 million) in unrecognized future income tax assets and approximately $nil in loss carryforwards (December 31, 2008 - $1.4 million) available to reduce future taxable income.

15. Financial Instruments and Risk Management

Financial Instrument Classification and Measurement

Financial instruments of the Trust carried on the Consolidated Balance Sheet are carried at amortized cost with the exception of cash and cash equivalents and financial derivative instruments, specifically fixed price contracts, which are carried at fair value. There are no significant differences between the carrying value of financial instruments and their estimated fair values as at December 31, 2009.

The fair value of the Trust's cash and cash equivalents and financial derivative instruments are quoted in active markets. The Trust classifies the fair value of these transactions according to the following hierarchy.

- *Level 1* – quoted prices in active markets for identical financial instruments.
- *Level 2* – quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant and significant value drivers are observable in active markets.
- *Level 3* – valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

The Trust's cash and cash equivalents and financial derivative instruments have been assessed on the fair value hierarchy described above and classified as Level 1.

Fair Values of Financial Assets and Liabilities

The Trust's financial instruments include cash, accounts receivable, financial derivative instruments, due from private placement, current liabilities (excluding future income tax), provision for future performance based compensation and long term debt. At December 31, 2009, the carrying value of cash and cash equivalents and financial derivative instruments are carried at fair value. Accounts receivable, due from private placement, current liabilities (excluding future income tax) and provision for future performance based compensation approximate their fair value due to their short term nature. The carrying value of the long term debt approximates its fair value due to the floating rate of interest charged under the credit facility.

Market Risk

Market risk is the risk that changes in market prices will affect the Trust's earnings or the value of its financial instruments. Market risk is comprised of commodity price risk and interest rate risk. The objective of market risk management is to manage and control exposures within acceptable limits, while maximizing returns. The Trust's objectives, processes and policies for managing market risks have not changed from the previous year.

Commodity Price Risk Management

The Trust is a party to certain 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 transactions and the underlying basis of the instruments correlate highly with the Trust's exposure. A summary of contracts outstanding in respect of the hedging activities at December 31, 2009 is as follows:

Description	Notional (1)	Term	Effective Rate	Fair Value Level	Asset (Liability) as at December 31, 2009	Asset (Liability) as at December 31, 2008
Natural gas financial swaps - AECO	23.38 GJ (2)	2010- 2012	$6.03/GJ	Level 1	9,936	30,246

(1) Notional values as at December 31, 2009 (2) Millions of gigajoules

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1 , 2009 to March 31, 2010	Fixed Price	5,000 GJ	$7.65/GJ
April 1 , 2009 to March 31, 2010	Fixed Price	5,000 GJ	$6.90/GJ
November 1, 2009 to March 31, 2010	Fixed Price	5,000 GJ	$8.39/GJ
November 1, 2009 to March 31, 2010	Fixed Price	5,000 GJ	$8.35/GJ
November 1, 2009 to March 31, 2010	Fixed price	5,000 GJ	$5.25/GJ
November 1, 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.20/GJ
November 1, 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.00/GJ
November 1, 2009 to March 31, 2011	Fixed Price	5,000 GJ	$6.20/GJ
November 1, 2009 to March 31, 2011	Fixed Price	5,000 GJ	$5.81/GJ
April 1, 2010 to October 31, 2010	Fixed price	5,000 GJ	$6.10/GJ
April 1, 2010 to March 31, 2011	Fixed price	5,000 GJ	$5.28/GJ
April 1, 2010 to March 31, 2011	Fixed price	5,000 GJ	$5.29/GJ
April 1, 2010 to March 31, 2011	Fixed price	5,000 GJ	$5.555/GJ
April 1, 2010 to March 31, 2012	Fixed price	5,000 GJ	$5.67/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$8.91/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$9.15/GJ
April 1, 2011 to March 31, 2012	Fixed price	5,000 GJ	$6.20/GJ

As at December 31, 2009, the Trust had committed to the future sale of 23,380,000 gigajoules (GJ) of natural gas at an average price of $6.03 per GJ or $7.05 per mcf based on the historical heating value of Peyto's natural gas. Had these contracts been closed on December 31, 2009, the Trust would have realized a gain in the amount of $9.9 million. If the AECO gas price on December 31, 2009 were to increase by $1/GJ, the unrealized gain on these closed contracts would change by approximately $23.4 million. An opposite change in commodity prices rates will result in an opposite impact on earnings which would have been reflected in the other comprehensive income of the Trust.

Subsequent to December 31, 2009 the Trust entered into the following contracts:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1, 2010 to October 31, 2010	Fixed price	5,000 GJ	$5.50/GJ
April 1, 2010 to March 31, 2011	Fixed price	5,000 GJ	$5.70/GJ
April 1, 2010 to March 31, 2012	Fixed price	5,000 GJ	$5.82/GJ

Interest rate risk

The Trust is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Trust has not entered into any agreements to manage this risk. If interest rates applicable to floating rate debt were to have increased by 100 bps (1%) it is estimated that the Trust's net income for the year ended December 31, 2009 would decrease by $4.7 million. An opposite change in interest rates will result in an opposite impact on earnings.

Credit Risk

A substantial portion of the Trust's accounts receivable is with petroleum and natural gas marketing entities.

Industry standard dictates that commodity sales are settled on the 25th day of the month following the month of production. 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 revenue for the year ended December 31, 2009, approximately 55% was received from the same three companies (21%, 20%, 14%, respectively) (December 31, 2008 – 90%, four companies (33%, 30%, 17% and 10%, respectively). The Trust had no significant individual accounts receivable at December 31, 2009 (December 31, 2008 – 35%, three companies (15%, 10%, 10%, respectively)). The maximum exposure to credit risk is represented by the carrying amount on the consolidated balance sheet. There are no material financial assets that the Trust considers past due and no accounts have been written off.

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.

Counterparties to financial instruments expose the Trust to credit losses in the event of non-performance. Counterparties for derivative instrument transactions are limited to high credit quality financial institutions, which are all members of our syndicated credit facility.

The Trust assesses quarterly if there should be any impairment of financial assets. At December 31, 2009, there was no impairment of any of the financial assets of the Trust.

Liquidity Risk
Liquidity risk includes the risk that, as a result of operational liquidity requirements:

- The Trust will not have sufficient funds to settle a transaction on the due date;
- The Trust will be forced to sell financial assets at a value which is less than what they are worth; or
- The Trust may be unable to settle or recover a financial asset at all.

The Trust's operating cash requirements, including amounts projected to complete our existing capital expenditure program, are continuously monitored and adjusted as input variables change. These variables include, but are not limited to, available bank lines, oil and natural gas production from existing wells, results from new wells drilled, commodity prices, cost overruns on capital projects and changes to government regulations relating to prices, taxes, royalties, land tenure, allowable production and availability of markets. As these variables change, liquidity risks may necessitate the need for the Trust to conduct equity issues or obtain project debt financing. The Trust also mitigates liquidity risk by maintaining an insurance program to minimize exposure to some losses.

The following are the contractual maturities of financial liabilities as at December 31, 2009:

($000s)	**<1 Year**	**1-2 Years**	**2-5 Years**	**Thereafter**
Accounts payable and accrued liabilities	55,890			
Distributions payable	13,790			
Provision for future market and reserves based bonus	2,001	1,041		
Long-term debt[(1)]		435,000		

[(1)]Revolving credit facility renewed annually (*see Note 7*)

16. Capital Disclosures

The Trust's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; and (ii) to maintain investor, creditor and market confidence to sustain the future development of the business.

The Trust manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of our underlying assets. The Trust considers its capital structure to include unitholders' equity, debt and working capital. To maintain or adjust the capital structure, the Trust may from time to time, issue trust units, raise debt and/or adjust its capital spending to manage its current and projected debt levels. The Trust monitors capital based on the following non-GAAP measures: current and projected debt to earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA") ratios, payout ratios and net debt levels. To facilitate the management of these ratios, the Trust prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. Currently, all ratios are within acceptable parameters. The annual budget is approved by the Board of Directors. The Trust's unitholders' capital is not subject to any external financial covenants.

There were no changes in the Trust's approach to capital management from the previous year.

($000s)	December 31, 2009	December 31, 2008
Unitholders' equity	**612,483**	550,717
Long-term debt	**435,000**	500,000
Working capital (surplus) deficit [(1)]	**(1,822)**	(32,075)
	1,045,661	1,018,642

[(1)]Current liabilities less current assets (includes unrealized hedging asset of $8.7 million (2008 - $27.8 million))

17. Supplemental Cash Flow Information

Changes in non-cash working capital balances

($000)	2009	2008
Accounts receivable	**7,357**	(17,934)
Prepaid expenses and deposits	**(420)**	1,653
Accounts payable and accrued liabilities	**7,035**	(37,069)
Cash distributions payable	**(2,098)**	1,088
Provision for future performance compensation	**3,042**	(269)
	14,916	(52,531)
Attributable to financing activities	**(2,098)**	1,088
Attributable to investing activities	**12,903**	(14,564)
Attributable to operating activities	**4,111**	(39,055)
	14,916	(52,531)

	2009	2008
Cash interest paid during the year	**16,527**	21,857

18. Contingencies and Commitments

Following is a summary of the Trust's commitments related to operating leases as at December 31, 2009. The Trust has no other contractual obligations or commitments as at December 31, 2009.

($000)	December 31, 2009
2010	1,036
2011	1,036
2012	1,036
2013	1,036
2014	1,036
	5,180

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 CNRL 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 the Trust's financial position or results of operations.

19. Related Party Transactions

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, 2009, legal fees totaled $0.6 million (2008 - $0.4 million). As at December 31, 2009, an amount due to this firm of $0.5 million was included in accounts payable (2008 - $0.1 million)

Peyto Exploration & Development Corp. Information

Officers

Darren Gee
President and Chief Executive Officer

Scott Robinson
Executive Vice-President and Chief Operating Officer

Kathy Turgeon
Vice President, Finance and Chief Financial Officer

Glenn Booth
Vice President, Land

Stephen Chetner
Corporate Secretary

Directors
Don Gray, Chairman
Rick Braund
Stephen Chetner
Brian Davis
Michael MacBean, Lead Independent Director
Darren Gee
Gregory Fletcher

Auditors
Deloitte & Touche LLP

Solicitors
Burnet, Duckworth & Palmer LLP

Bankers
Bank of Montreal
Union Bank, Canada Branch
BNP Paribas (Canada)
Royal Bank of Canada
Alberta Treasury Branches
Société Générale (Canada Branch)
HSBC Bank Canada
Canadian Western Bank

Transfer Agent
Valiant Trust Company

Head Office
1500, 250 – 2nd Street SW
Calgary, AB
T2P 0C1

Phone: 403.261.6081
Fax: 403.451.4100
Web: www.peyto.com

Stock Listing Symbol: PEY.un
Toronto Stock Exchange