NEWS RELEASE

MARCH 9, 2011 **SYMBOL: PEY – TSX**

PEYTO EXPLORATION & DEVELOPMENT CORP. ANNOUNCES Q4 AND 2010 YEAR END REPORT TO SHAREHOLDERS

CALGARY, ALBERTA – Peyto Exploration & Development Corp. (formerly Peyto Energy Trust) is pleased to present the operating and financial results for the fourth quarter and 2010 fiscal year. Peyto had a very successful year in 2010, delivering 28% growth in production/share, 73% operating margin[1], 38% profit margin[2], 10% return on capital and 17% return on equity. Highlights for 2010 include:

- Grew production 47% from 115 MMCFe/d (19,133 boe/d) in Q4 2009 to 169 MMCFe/d (28,197 boe/d) in Q4 2010 or 28%/share.
- Grew Proved Producing ("PP"), Total Proved ("TP") and Proved plus Probable Additional ("P+P") reserves by 12%, 21%, and 30% (-3%, 5%, and 13% per share) to 0.7, 1.1, and 1.6 TCFe, respectively. All in FD&A costs for PP, TP and P+P reserves were $2.10/MCFe ($12.63/boe), $2.35/MCFe and $2.19/MCFe including changes in future development capital.
- Invested $261 million to build a record 91 MMCFe/d (15,100 boe/d) of new production at a cost of $17,300/boe/d.
- Reduced industry leading operating costs 15% to $0.35/MCFe ($2.13/boe) from $0.41/MCFe ($2.48/boe) in 2009.
- Generated $234 million in Funds from Operations ($1.94/share) and $122 million in Earnings ($1.01/share).
- Reduced net debt 8% to $405 million, leaving $220 million of available capacity on bank lines of $625 million.
- Distributed $175.3 million to unitholders ($1.44/unit).
- Net Asset value or the NPV per share, debt adjusted (discounted at 5%) of the Proved plus Probable Additional assets remained at $33/share for the third year in a row.

2010 in Review

Peyto has now completed its twelfth year of operations. Using the proven application of horizontal wells with multi-stage fracture treatments, the company executed a much larger capital program than the previous year but at similar capital efficiency; building new production for $17,300 per flowing boe. This meant a record 15,100 boe/d of new production was on-stream by year end. At the same time, Peyto expanded three of its gas plants to accommodate this new production and, through continued land capture and development activity, replaced each drilled location with two new undeveloped locations. The profitability of this growth was measured by the internal rate of return on the year's capital investment of $261 million. At year end, this return was estimated to be 33%. This is not the best annual return ever generated by Peyto, but considering the low natural gas price environment, it is a very satisfactory result. Alberta natural gas prices spent three quarters of the year below $4/GJ, driven by an abundance of supply in North America. In contrast, Edmonton light oil prices averaged over $75/bbl, meaning oil sold for more than three times that of natural gas, when converted at 6 mcf to 1 bbl. Peyto's Deep Basin natural gas stream, which is rich in natural gas liquids like condensate, propane and butane, was worth 40% more than dry gas due to the difference between gas and oil prices. Equipped with a low cost advantage and an abundance of similar undeveloped opportunities, the Peyto team will continue to focus on delivering profitable growth and an attractive total return with shareholder's capital in 2011.

(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		%
	2010	2009	Change	**2010**	2009	Change
Operations						
Production						
Natural gas (mcf/d)	**148,551**	95,467	*56%*	**122,031**	92,718	*32%*
Oil & NGLs (bbl/d)	**3,439**	3,222	*7%*	**3,389**	3,028	*12%*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**169,184**	114,798	*47%*	**142,366**	110,884	*28%*
Barrels of oil equivalent (boe/d @ 6:1)	**28,197**	19,133	*47%*	**23,728**	18,481	*28%*
Product prices						
Natural gas ($/mcf)	**4.93**	6.17	*(20)%*	**5.36**	6.44	*(17)%*
Oil & NGLs ($/bbl)	**67.06**	60.77	*10%*	**65.31**	50.18	*30%*
Operating expenses ($/mcfe)	**0.31**	0.38	*(18)%*	**0.35**	0.41	*(15)%*
Transportation ($/mcfe)	**0.14**	0.11	*27%*	**0.13**	0.11	*18%*
Field netback ($/mcfe)	**4.75**	5.64	*(16)%*	**5.02**	5.60	*(10)%*
General & administrative expenses ($/mcfe)	**0.13**	0.15	*(13)%*	**0.12**	0.18	*(33)%*
Interest expense ($/mcfe)	**0.36**	0.44	*(18)%*	**0.39**	0.41	*(5)%*
Financial ($000, except per share)						
Revenue	**88,633**	72,218	*23%*	**319,426**	273,517	*17%*
Royalties	**7,712**	7,457	*3%*	**33,405**	25,671	*30%*
Funds from operations	**66,359**	53,302	*24%*	**234,077**	202,699	*15%*
Funds from operations per share	**0.53**	0.46	*15%*	**1.94**	1.83	*6%*
Total distributions	**46,299**	41,371	*12%*	**175,268**	163,263	*7%*
Total distributions per share	**0.36**	0.36	-	**1.44**	1.47	*(2)%*
Payout ratio	**70**	78	*(10)%*	**75**	81	*(7)%*
Earnings	**27,700**	33,035	*(16)%*	**121,838**	152,774	*(20)%*
Earnings per share	**0.22**	0.28	*(21)%*	**1.01**	1.38	*(27)%*
Capital expenditures	**110,561**	26,307	*320%*	**261,484**	72,739	*259%*
Weighted average shares outstanding	**125,726,450**	114,920,194	*9%*	**120,548,796**	110,555,810	*9%*
As at December 31						
Net debt (before future compensation expense and unrealized hedging gains)				**404,944**	439,860	*(8%)*
Shareholders' equity				**838,646**	612,483	*37%*
Total assets				**1,454,575**	1,254,113	*16%*

($000)	3 Months Ended December 31		12 Months Ended December 31	
	2010	2009	**2010**	2009
Cash flows from operating activities	**65,545**	46,567	**222,532**	198,688
Change in non-cash working capital	**(21,594)**	389	**(22,297)**	(4,111)
Change in provision for performance based compensation	**(7,456)**	1,266	**3,978**	3,042
Performance based compensation	**29,864**	5,080	**29,864**	5,080
Funds from operations	**66,359**	53,302	**234,077**	202,699
Funds from operations per share	**0.53**	0.39	**1.94**	1.83

(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 dividends may vary.

Capital Expenditures

Net capital expenditures for 2010 totaled $261.5 million, a 259% increase from 2009. Invested capital represented 112% of annual funds from operations, as Peyto aggressively invested in building new production and infrastructure. Drilling, completions and well connections accounted for $224 million or 86% of the capital (net of $11.7 million in drilling royalty credits) with facility expansions accounting for $19 million or 7%. Over 98 sections of new deep basin lands were purchased with 5% of the total capital, at an average cost of $195/acre. The majority of this new land is adjacent to Peyto's existing infrastructure and has identified drilling locations on it.

During the year Peyto spud 52 gross (48.1 net) wells, 45 of which were horizontal, and brought on production 52 gross (49.2 net) new gas zones. The average horizontal well cost $3.0 million to drill and $1.6 million to complete, before any Drilling Royalty Credit or Natural Gas Deep Drilling Program royalty holiday. Beyond March 31, 2011, a drilling royalty credit of $200 per meter drilled will no longer be available. After May 1, 2010 the crown revised the natural gas deep drilling incentive, effectively making all of the formations that Peyto targets eligible for this holiday. The average 2010 qualifying horizontal well earned over $1.5 million in royalty holiday.

The Greater Sundance core area was the focus of the majority of the 2010 capital expenditures with 44 wells drilled and with all three gas plants undergoing expansion. The remaining capital was focused on liquids rich Cardium gas development in the northern areas of Kakwa and Cutbank. The following table summarizes capital expenditures for the year.

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2010**	2009	**2010**	2009
Land	**8,049**	1,150	**12,600**	4,115
Seismic	**92**	644	**224**	1,470
Drilling – Exploratory & Development	**82,561**	27,449	**205,567**	66,926
Production Equipment, Facilities & Pipelines	**14,766**	4,993	**49,100**	11,417
Acquisitions	**5,024**	-	**5,724**	-
Drilling Royalty Credit	**69**	(7,942)	**(11,731)**	(11,342)
Office Equipment	**-**	13	**-**	153
Total Capital Expenditures	**110,561**	26,307	**261,484**	72,739

Reserves

Peyto was active in the development of existing proved and probable undeveloped reserves in 2010, as well as identifying and securing new undeveloped reserves. The following table illustrates the change in reserve volumes and Net Present Value ("NPV") of future cash flows, discounted at 5%, before income tax, using forecast pricing.

	As at December 31		% Change	% Change, debt adjusted per share†
	2010	2009		
Reserves (BCFe)				
Proved Producing	**664**	591	*12%*	*6%*
Total Proved	**1,078**	893	*21%*	*14%*
Proved + Probable Additional	**1,558**	1,199	*30%*	*23%*
Net Present Value ($millions) Discounted at 5%				
Proved Producing	**$2,363**	$2,389	*-1%*	*-13%*
Total Proved	**$3,404**	$3,344	*2%*	*-10%*
Proved + Probable Additional	**$4,738**	$4,295	*10%*	*-3%*

†Per share or unit, reserves are adjusted for changes in net debt by converting debt to equity using the Dec 31 unit price of $14.06 for 2009 and share price of $18.49 for 2010. Net Present Values are adjusted for debt by subtracting net debt from the value prior to calculating per share amounts.

Note: based on the InSite Petroleum Consultants report effective December 31, 2010. The InSite price forecast is available at www.InSitepc.com. For more information on Peyto's reserves, refer to the Press Release dated February 16, 2011 announcing the 2010 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 2011.

Performance Ratios

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

	2010	2009	2008	2007	2006
Proved Producing					
FD&A ($/mcfe)	**$2.10**	$2.26	$2.88	$2.11	$2.95
RLI (yrs)	**11**	14	14	13	12
Recycle Ratio	**2**	1.8	2.3	2.8	2
Reserve Replacement	**239%**	79%	110%	127%	211%
Total Proved					
FD&A ($/mcfe)	**$2.35**	$1.73	$3.17	$1.57	$3.28
RLI (yrs)	**17**	21	17	16	14
Recycle Ratio	**1.8**	2.3	2.1	3.7	1.8
Reserve Replacement	**456%**	422%	139%	175%	194%
Future Development Capital ($ millions)	**$741**	$446	$222	$169	$166
Proved plus Probable Additional					
FD&A ($/mcfe)	**$2.19**	$1.47	$3.88	$1.56	$2.90
RLI (yrs)	**25**	29	23	21	20
Recycle Ratio	**1.9**	2.8	1.7	3.7	2
Reserve Replacement	**790%**	597%	122%	117%	220%
Future Development Capital ($millions)	**$1,310**	$672	$390	$321	$360

- 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 ($261.5+$295)/(179.7-148.9+8.661) = $14.09/boe or $2.35/mcfe).

- The reserve life index (RLI) is calculated by dividing the reserves (in boes) in each category by the annualized average production rate in boe/year (eg. Proved Producing 110,619/(28.197x365) = 11). Peyto believes that the most accurate way to evaluate the current reserve life is by dividing the proved developed producing reserves by the actual fourth quarter average production. In Peyto's opinion, for comparative purposes, the proved developed producing reserve life provides the best measure of sustainability.

- 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 (($4.17)/$2.10=2.0). 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 replacement ratio is determined by dividing the yearly change in reserves before production by the actual annual production for the year (eg. Total Proved ((179.7-148.86+8.661)/8.661) = 4.56).

Value Creation/Reconciliation

In order to measure the success of the 2010 capital program, it is necessary to quantify the total amount of value created during the year and compare that to the total amount of capital invested. At Peyto's request, and for the benefit of shareholders, 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 2010 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 (now shares) outstanding to see if the change in value is truly accretive to shareholders.

At year end 2010, Peyto's estimated net debt had decreased by $35 million to $405 million while the number of units (now shares) outstanding had increased by 17.7 million to 132.8 million shares. 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. Although these estimates are believed to be accurate, they remain unaudited at this time and are subject to change.

Based on this reconciliation of changes in BT NPV, the Peyto team was able to create $911 million of Proved Producing, $1.59 billion of Total Proven, and $2.69 billion of Proved plus Probable Additional undiscounted reserve value, with $261 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 2010, the Proved Producing NPV recycle ratio is 3.5.

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, 2010.

	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, 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**	**$2,188**
Per Unit Outstanding at Dec. 31, 2009 ($/unit or share)	$36.62	$16.93	$9.89	$53.95	$25.23	$14.65	$74.69	$33.49	$19.01
2010 sales (revenue less royalties and operating costs)	**($261)**	**($261)**	**($261)**	**($261)**	**($261)**	**($261)**	**($261)**	**($261)**	**($261)**
Net Change due to price forecasts (using InSite Jan 1, 2011 price forecast)	**($767)**	**($402)**	**($271)**	**($1,155)**	**($610)**	**($410)**	**($1,494)**	**($754)**	**($494)**
Value Change due to discoveries (additions, extensions, transfers, revisions)	**$911**	**$672**	**$571**	**$1,594**	**$966**	**$711**	**$2,691**	**$1,493**	**$1,004**
Before Tax Net Present Value at End of Year ($millions)									
Dec. 31, 2010 Evaluation using InSite Jan. 1, 2011 price forecast, less debt	**$4,098**	**$1,958**	**$1,177**	**$6,388**	**$2,999**	**$1,727**	**$9,534**	**$4,333**	**$2,438**
Per Share Outstanding at Dec. 31, 2010 ($/share)	$30.85	$14.75	$8.86	$48.10	$22.58	$13.00	$71.79	$32.63	$18.36
Year over Year Change in Before Tax NPV/unit or share	**(16%)**	**(13%)**	**(10%)**	**(11%)**	**(10%)**	**(11%)**	**(4%)**	**(3%)**	**(3%)**
Year over Year Change in Before Tax NPV/unit or share including Distribution ($1.44/unit)	**(12%)**	**(4%)**	**4%**	**(8%)**	**(5%)**	**(1%)**	**(2%)**	**2%**	**4%**

Tables may not add due to rounding.

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 2010, the Proved Producing NPV recycle ratio was 3.5 times. This means for each dollar invested, the Peyto team was able to create 3.5 new dollars of Proved Producing reserve value. The average NPV Recycle Ratio over the last 5 years is 3.7 times for undiscounted future values or 2.5 times for future values discounted at 10%. The historic NPV recycle ratio is presented in the following table.

2010 Value Creation	**Dec 31, 2010**	Dec 31, 2009	Dec 31, 2008	Dec 31, 2007	Dec 31, 2006
NPV_0 Recycle Ratio					
Proved Producing	**3.5**	5.4	2.1	4.7	2.9
Total Proved	**6.1**	18.9	2.5	5.5	2.9
Proved + Probable Additional	**10.3**	27.1	2.2	3.8	3.8

- 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 ($911/$261.5) = 3.5).

Quarterly Review

Capital expenditures for the fourth quarter 2010 increased to $110.6 million up 320% from Q4 2009, as the company continued to aggressively grow the asset base. Drilling and completions accounted for $82.6 million while production equipment, pipelines and facilities accounted for $14.8 million. Land, seismic, and a small acquisition/joint venture in the Nosehill area made up the balance of the capital expenditures at $13.2 million.

Daily production for Q4 2010 averaged 169 MMCFe/d (28,197 boe/d) up 47% from 115 MMCFe/d in Q4 2009. Natural gas production of 148.6 mmcf/d and oil and natural gas liquids production of 3,439 bbls/d combined for the increase. Natural gas prices, before hedging effects, were 19% lower than Q4 2009 at $3.89/mcf, while liquids prices were 10% higher at $67.06/bbl. Forward sales of natural gas contributed a hedging gain of $1.04/mcf in Q4 2010, and resulted in a realized gas price of $4.93/mcf. Total revenue for Q4 2010 was up 23% from Q4 2009 due to increased volumes, despite 20% lower overall price realizations.

Fourth quarter 2010 cash costs, comprised of royalties, operating costs, transportation, G&A and interest were 20% lower than Q4 2009 at $1.44/MCFe. Higher production volumes were the primary driver of lower overall per unit costs, although reduced chemical consumption, enhanced royalty incentives, and a larger capital program with greater overhead recovery also contributed.

Total revenue of $5.70/mcfe ($34.20/boe) in Q4 2010, less cash costs of $1.44/mcfe, resulted in a cash netback of $4.26/mcfe or $25.58/boe, down 16% from the prior year. This cash netback to revenue ratio translated into a 75% operating margin.

Marketing

Alberta monthly natural gas prices averaged less than $4/GJ again in 2010, as the over supplied North American market persisted. The future prices offered for natural gas in Canada and the US imply this condition will continue throughout 2011 and into 2012, although more evidence is emerging to suggest this is less than the price required for the profitable development of the many shale gas plays in the US. Nonetheless, Peyto’s low cost structure and high heat content natural gas allow the company to be profitable at these prices.

Peyto continues to execute a simple but effective marketing strategy designed to smooth out the volatility in natural gas prices through future sales. This strategy was again successful in 2010 as Peyto realized a natural gas price of $5.36/mcf versus an AECO monthly average price of $4.36/mcf.

Details of the individual contracts are available in Management's Discussion and Analysis ("MD&A"). As at December 31, 2010, Peyto had committed to the future sale of 24,010,000 gigajoules (GJ) of natural gas at an average price of $5.07 per GJ or $5.93 per mcf. Had these contracts been closed on December 31, 2010, the company would have realized a gain in the amount of $27.9 million.

Corporate Conversion

The year 2010 marked Peyto's last year as an energy Trust. On December 8, 2010 Peyto announced the receipt of unitholder and court approvals for its conversion to a corporation. With unitholders voting in excess of 99.8% in favor of the plan of arrangement, the conversion became effective on December 31, 2010 and the common shares of Peyto began trading under the symbol "PEY" on the Toronto Stock Exchange on January 7, 2011.

The Board of Directors is also pleased to confirm the monthly dividend for the second quarter of 2011 will remain at $0.06/share.

Activity Update

To date in 2011, six drilling rigs have been active in Peyto's Deep Basin core areas. The company has drilled and rig released 14 gross (12.5 net) wells, 6 gross (5.4 net) of which were spud during 2010. All the wells drilled to date are horizontals. Four wells (3.6 net) are currently awaiting completion.

Peyto has brought on-stream 11 gross (9.3 net) new wells since the beginning of 2011. These wells are producing a combined 27 MMCfe/d (4,500 boe/d). Total company production currently ranges between 192 MMCfe/d (32,000 boe/d) and 198 MMCFe/d (33,000 boe/d) as new wells are at various stages of in-line testing and tie-in.

As March draws to an end, the six active drilling rigs are expected to be situated on multi-well drill pads that should allow for continuous operations during the traditional April and May spring break up months. A 25 MMcf/d expansion of the Wildhay gas plant is expected to be completed by the end of May. A major expansion of the Nosehill gas plant will follow in late July and will involve the addition of 50 MMcf/d of gas processing capacity. These two expansions will eventually allow for combined production growth of over 75 MMCFe/d (12,500 boe/d).

2011 Outlook

Building on the success of the 2010 capital program, Peyto looks to execute an even larger capital program in 2011 of $300-$325 million. With an ever growing inventory of drilling locations and a strict focus on cost control, the Peyto team will again endeavor to deliver significant profitable growth and real returns for shareholders. At the same time, a $0.06/month dividend allows Peyto shareholders to enjoy income along the way.

Conference Call and Webcast

A conference call will be held with the senior management of Peyto to answer questions with respect to the 2010 fourth quarter and full year financial results on Thursday, March 10, 2011, at 9:00 a.m. Mountain Standard Time (MST), or 11:00 a.m. Eastern Standard Time (EST). To participate, please call 1-416-340-2216 (Toronto area) or 1- 866-226-1792 for all other participants. The conference call will also be available on replay by calling 1-905-694-9451 (Toronto area) or 1-800-408-3053 for all other parties, using passcode 5676357. The replay will be made available at 11:00 a.m. MST or 1:00 p.m. EST Thursday, March 10, 2011 until midnight EDT on Thursday, March 17th, 2011. The live conference call can also be accessed through the internet at http://events.digitalmedia.telus.com/peyto/031011/index.php. After this time the conference call will be archived on the Peyto Exploration & Development Corp. website at www.peyto.com.

Management's Discussion and Analysis

A copy of the fourth quarter report to shareholders, including the Management's Discussion and Analysis, and audited financial statements and related notes is available at http://www.peyto.com/news/Q42010MDandA.pdf and will be filed at SEDAR, www.sedar.com , at a later date.

Annual General Meeting

Peyto's Annual General Meeting of Shareholders is scheduled for 3:00 p.m. on Wednesday, May 18, 2011 at Livingston Place Conference Centre, +15 level, 222-3rd Avenue SW, Calgary, Alberta.

Shareholders 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 9, 2011

Certain information set forth in this document and Management's Discussion and Analysis, including management's assessment of Peyto'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 Peyto will derive therefrom.

Peyto Exploration & Development Corp.

Consolidated Balance Sheets
($000)

	December 31, 2010	December 31, 2009
Assets		
Current		
Cash	**7,894**	-
Accounts receivable *(Note 4)*	**55,876**	58,305
Due from private placement *(Note 8)*	**12,423**	2,728
Financial derivative instruments *(Note 14)*	**25,247**	8,683
Prepaid expenses	**3,280**	3,787
	104,720	73,503
Financial derivative instruments *(Note 14)*	**2,664**	1,253
Prepaid capital	**-**	955
Property, plant and equipment *(Note 5)*	**1,347,191**	1,178,402
	1,349,855	1,180,610
	1,454,575	1,254,113
Liabilities and Shareholders' Equity		
Current		
Accounts payable and accrued liabilities	**113,592**	55,890
Cash distributions payable *(Note 9)*	**15,825**	13,790
Provision for future performance based compensation *(Note 12)*	**5,567**	2,001
	134,984	71,681
Long-term debt *(Note 6)*	**355,000**	435,000
Provision for future performance based compensation *(Note 12)*	**1,452**	1,041
Asset retirement obligations *(Note 7)*	**11,926**	10,487
Future income taxes *(Note 13)*	**112,567**	123,421
	480,945	569,949
Shareholders' or Unitholders' Equity		
Shareholders' capital *(Note 8)*	**754,493**	-
Unitholders' capital *(Note 8)*	**-**	500,407
Common shares to be issued *(Note 8)*	**17,285**	2,728
Retained earnings *(Note 9)*	**46,319**	99,749
Accumulated other comprehensive income	**20,549**	9,599
	66,868	109,348
	838,646	612,483
	1,454,575	1,254,113

See accompanying notes

On behalf of the Board:

(signed) *"Michael MacBean"* — Director

(signed) *"Darren Gee"* — Director

Peyto Exploration & Development Corp.

Consolidated Statements of Earnings

($000 except per share amounts)

For the years ended December 31,

	2010	2009
Revenue		
Oil and gas sales	**275,081**	210,530
Realized gain on hedges	**44,345**	62,987
Royalties	**(33,405)**	(25,671)
Petroleum and natural gas sales, net	**286,021**	247,846
Expenses		
Operating *(Note 10)*	**18,415**	16,736
Transportation	**6,954**	4,541
General and administrative*(Note 11)*	**6,518**	7,292
Performance based compensation *(Note 12)*	**29,864**	5,080
Future performance based compensation *(Note 12)*	**3,978**	3,042
Interest on long term debt	**20,057**	16,527
Depletion, depreciation and accretion *(Notes 5 and 7)*	**94,184**	73,298
	179,970	126,516
Earnings before taxes	**106,051**	121,330
Taxes		
Future income tax recovery *(Note 13)*	**15,787**	31,444
Earnings for the year	**121,838**	152,774
Earnings per share or unit *(Note 8)*		
Basic and diluted	**1.01**	1.38

See accompanying notes

Peyto Exploration & Development Corp.

Consolidated Statements of Comprehensive Income
($000)

For the years ended December 31,

	2010	2009
Earnings for the year	**121,838**	152,774
Other comprehensive income		
Change in unrealized gain on cash flow hedges (net of future income tax, 2010 - $7.0 million, 2009 - $0.3 million)	**55,295**	42,340
Realized (gain) loss on cash flow hedges	**(44,345)**	(62,987)
Comprehensive Income	**132,788**	132,127

See accompanying notes

Peyto Exploration & Development Corp.

Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income

($000)

For the years ended December 31,

	2010	2009
Retained earnings, beginning of year	**99,749**	110,238
Earnings for the year	**121,838**	152,774
Distributions *(Note 9)*	**(175,268)**	(163,263)
Retained earnings, end of year	**46,319**	99,749
Accumulated other comprehensive income, beginning of year	**9,599**	30,246
Other comprehensive income (loss)	**10,950**	(20,647)
Accumulated other comprehensive income, end of year	**20,549**	9,599

See accompanying notes

Peyto Exploration & Development Corp.

Consolidated Statements of Cash Flows

($000)

For the years ended December 31,

	2010	2009
	$	$
Cash provided by (used in)		
Operating Activities		
Earnings for the year	**121,838**	152,774
Items not requiring cash:		
Future income tax recovery	**(15,787)**	(31,444)
Depletion, depreciation and accretion	**94,184**	73,298
Change in non-cash working capital related to operating activities *(Note 16)*	**22,297**	4,060
	222,532	198,688
Financing Activities		
Issue of common shares	**262,292**	94,500
Issuance costs	**(8,272)**	(5,106)
Cash distributions paid	**(162,736)**	(163,263)
Decrease in bank debt	**(80,000)**	(65,000)
Change in non-cash working capital related to financing activities *(Note 16)*	**(7,660)**	(2,098)
	3,624	(140,967)
Investing Activities		
Additions to property, plant and equipment	**(260,581)**	(70,624)
Change in non-cash working capital related to investing activities *(Note 16)*	**42,319**	12,903
	(218,262)	(57,721)
Net increase in cash	**7,894**	-
Cash, beginning of year	**-**	-
Cash, end of year	**7,894**	-

See accompanying notes

Peyto Exploration & Development Corp.

Notes to Consolidated Financial Statements

December 31, 2010 and 2009

1. Nature of Operations

Peyto Exploration & Development Corp. (the "Company" or "Peyto") is a Company established under the laws of the Province of Alberta. The Shareholders of the Company are entitled to receive cash dividends paid by the Company and are entitled to one vote for each common share held at shareholder meetings.

The common shares trade on the TSX under the symbol "PEY.TO". The Company's principal business activity is the exploration for, development and production of petroleum and natural gas in western Canada.

On December 31, 2010, Peyto completed the conversion from a trust to a corporation pursuant to a plan of arrangement under the *Business Corporations Act* (Alberta). Peyto Energy Trust (the "Trust") was dissolved and the Company, together with its subsidiaries, received all of the assets and assumed all of the liabilities of the Trust. As a result of this conversion, the units of the Trust were exchanged for common shares of Peyto on a one-for-one basis (see Note 8).

The conversion has been accounted for as a continuity of interests and all comparative information presented for the pre-conversion period is that of the Trust. All transaction costs associated with the conversion were expensed as incurred as general and administration expense.

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 Company's accounting policies summarized below.

These consolidated financial statements include the accounts of Peyto Exploration and Development Corp. and all other Peyto entities.

Cash Equivalents
Cash equivalents include market deposits and similar type instruments, with an original maturity of three months or less when purchased. The Company did not hold any cash equivalents at the end of the year.

Joint operations
The Company 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 Company's proportionate interest in such activities.

Property, plant and equipment
The Company 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 Company 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 declining basis over a 20-year term. Office furniture and equipment are depreciated over their estimated useful lives at declining balance basis between 20% and 30% per year.

Asset retirement obligations

The Company 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 Company uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. The Company does not enter into derivative financial instruments for trading or speculative purposes. All derivative financial instruments are initiated within the guidelines of the Company'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 Company 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 Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Future income taxes

The Company 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 Company has classified each financial instrument into the following categories: "held for trading"; "loans & receivables"; and "other 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 Company 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 Company to manage market risk against volatility in commodity prices. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company has chosen to designate its existing derivative instruments as cash flow hedges. The Company 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 Company has no contracts containing embedded derivatives.

3. Pending Accounting Pronouncements

International Financial Reporting Standards ("IFRS")

In October 2009, the Accounting Standards Board issued a third and final IFRS Omnibus Exposure Draft confirming that publicly accountable enterprises will be required to apply IFRS, in full and without modification, for all financial periods beginning January 1, 2011. The transition to IFRS at January 1, 2011 requires the restatement, for comparative purposes, of amounts reported by the Company for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

4. Accounts Receivable

($000)	2010	2009
Accounts receivable – general	**48,721**	51,150
Accounts receivable – income taxes	**7,155**	7,155
	55,876	58,305

Canada Revenue Agency ("CRA") conducted an audit of Peyto's restructuring costs incurred in the 2003 trust conversion. On September 25, 2008, the CRA reassessed on the basis that $41 million of these costs were not deductible and treated them as an eligible capital amount. Peyto filed a notice of objection and the CRA confirmed the reassessment. Examinations for discovery have been completed. A trial date has not been set. The Tax Court of Canada has agreed to both parties' request to hold Peyto's appeal in abeyance pending a decision of the Federal Court of Appeal in another taxpayer's appeal. The other appeal raises issues that are similar in principle to those raised in Peyto's appeal. Based upon consultation with legal counsel, Management’s view is that it is likely that Peyto’s appeal will succeed.

5. Property, Plant and Equipment

($000)	2010	2009
Property, plant and equipment	**1,886,885**	1,624,655
Accumulated depletion and depreciation	**(539,694)**	(446,253)
	1,347,191	1,178,402

At December 31, 2010 costs of $36.4 million (December 31, 2009 - $26.6 million) related to undeveloped land have been excluded from the depletion and depreciation calculation.
The Company performed a ceiling test calculation at December 31, 2010 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, 2010 using the following independent engineering consultant’s forecasted prices:

	2011	2012	2013	2014	2015	Thereafter (1)
Edmonton Ref Price ($CDN/bbl)	87.30	90.28	93.83	95.88	97.92	+2.0%
CDN/US Exchange rate	0.98	0.97	0.96	0.96	0.96	0.96
AECO ($CDN/mmbtu)	4.14	4.71	5.29	5.76	6.27	+2.6%

(1) Percentage change for the Edmonton Ref Price and the AECO Price of 2.0% and 2.6% respectively, represents the average change in future prices each year after 2015 to the end of the reserve life.

6. Long-Term Debt

The Company has a syndicated $625 million extendible revolving credit facility with a stated term date of April 30, 2011. The facility is made up of a $20 million working capital sub-tranche and a $605 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 Company, 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 further 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 Company’s debt to earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) ratio that range from prime to prime plus 1.25% to 2.75% for debt to EBITDA ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank. The average borrowing rate for 2010 was 4.6% (2009 – 3.5%).

7. Asset Retirement Obligations

The total future asset retirement obligations are estimated by Management based on the Company'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 Company has estimated the net present value of its total asset retirement obligations to be $11.9 million as at December 31, 2010 (2009 - $10.5 million) based on a total future liability of $39.6 million (2009 - $36.0 million). These payments are expected to be made over the next 50 years. The Company'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)	**2010**	2009
Balance, December 31, 2009	**10,487**	9,479
Increase in liabilities relating to investing activities	**696**	341
Accretion expense	**743**	667
Balance, December 31, 2010	**11,926**	10,487

8. Shareholders' Capital and Unitholders' Capital

Authorized: Unlimited number of voting common shares or units

Issued and Outstanding

Trust Units (no par value) ($000)	**Number of Units**	**Amount**
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**
Trust units issued by private placement	196,420	2,728
Trust units issued	13,880,500	218,704
Trust units issuance costs (net of tax)	-	(8,206)
Trust units issued pursuant to DRIP	746,079	10,558
Trust units issued pursuant to OTUPP	2,132,189	30,302
Exchange for common shares pursuant to the Arrangement *(Note 1)*	(131,875,382)	(754,493)
Balance, December 31, 2010	**-**	**-**

Common Shares (no par value) ($000)	**Number of Shares**	**Amount**
Issuance of common shares for trust units pursuant to the Arrangement *(Note 1)*	131,875,382	754,493
Balance, December 31, 2010	**131,875,382**	**754,493**

Units Issued

On November 30, 2010, Peyto closed an offering of 8,314,500 trust units at a price of $17.30 per trust unit, receiving proceeds of $138.8 million (net of issuance costs).

On April 27, 2010, Peyto closed an offering of 5,566,000 trust units at a price of $13.45 per trust unit, receiving proceeds of $71.7 million (net of issuance costs).

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 $90.2 million (net of issuance costs).

On December 31, 2009 the Company completed a private placement of 196,420 common shares to employees and consultants for net proceeds of $2.7 million ($13.89 per share). These common shares were issued on January 6, 2010.

Peyto reinstated its amended distribution reinvestment and optional trust unit purchase plan (the "Amended DRIP Plan") effective with the January 2010 distribution whereby eligible Unitholders may elect to reinvest their monthly cash distributions in additional trust units at a 5% discount to market price. The DRIP plan incorporates an Optional Trust Unit Purchase Plan ("OTUPP") which provides unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP.

Common Shares Issued

On December 31, 2010, Peyto converted all outstanding trust units into common shares on a one share per trust unit basis. At December 31, 2010 there were 131,875,382 shares outstanding. The DRIP and the OTUPP plans were cancelled December 31, 2010.

Common Shares to be Issued

On December 31, 2010 the Company completed a private placement of 655,581 common shares to employees and consultants for net proceeds of $12.4 million ($18.95 per share). These common shares were issued on January 6, 2011.

Subsequent to December 31, 2010, 279,723 common shares (113,527 pursuant to the DRIP and 166,196 pursuant to the OTUPP) were issued for net proceeds of $4.9 million. Subsequent to the issuance of these shares, 132,810,686 common shares were outstanding.

Per Share or Per Units Amounts

Earnings per share or unit have been calculated based upon the weighted average number of common shares outstanding during the year of 120,548,796 (2009 - 110,555,810). There are no dilutive instruments outstanding.

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.

9. Accumulated Distributions

During the year, the Company paid distributions to the Unitholders in the aggregate amount of $175.3 million (2009 - $163.3 million total) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Share (1)
January 2010	January 31, 2010	February 15, 2010	$0.12
February 2010	February 28, 2010	March 15, 2010	$0.12
March 2010	March 31, 2010	April 15, 2010	$0.12
April 2010	April 30, 2010	May 14, 2010	$0.12
May 2010	May 31, 2010	June 15, 2010	$0.12
June 2010	June 30, 2010	July 15, 2010	$0.12
July 2010	July 31, 2010	August 13, 2010	$0.12
August 2010	August 31, 2010	September 15, 2010	$0.12
September 2010	September 30, 2010	October 15, 2010	$0.12
October 2010	October 31, 2010	November 15, 2010	$0.12
November 2010	November 30, 2010	December 15, 2010	$0.12
December 2010	December 31, 2010	January 15, 2011	$0.12

(1) Distributions per trust unit reflect the per trust unit amounts declared monthly to Unitholders.

Retained Earnings and Distributions

($000)	**2010**	2009
Retained earnings, beginning of year	**1,072,209**	919,435

Earnings for the year	**121,838**	152,774
Total retained earnings	**1,194,047**	1,072,209
Total accumulated distributions	**(1,147,728)**	(972,460)
Retained earnings, end of year	**46,319**	99,749

10. Operating Expenses

The Company'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)	**2010**	2009
Field expenses	**28,960**	27,487
Processing and gathering income	**(10,545)**	(10,751)
Total Operating expenses	**18,415**	16,736

11. General and Administrative Expenses

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

($000)	**2010**	2009
General and Administrative expenses	**11,063**	9,797
Overhead recoveries	**(4,545)**	(2,505)
Net General and administrative expenses	**6,518**	7,292

12. Performance Based Compensation

The Company 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, dividends, 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 share values)	2010	2009	**Change**
Net present value of proved producing reserves @ 8% based on constant Independent Reservoir Engineers' 2011 price forecast	1,254.0	1,178.0	
Net debt before performance based compensation	(392.4)	(439.9)	
2010 distributions, general and administration and interest expense	-	(201.8)	
Net value	861.6	536.3	
Shares/units outstanding	131.875	115.117	
Net value per share/unit	6.532	4.658	**1.874**
Units outstanding at beginning of year			**115.117**
Equity adjusted increase in value			**215.7**
2010 reserve value based compensation @ 4%			**8.6**

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 common shares 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 dividends of a share for that period. The 2010 market based component was based on i) 1.5 million vested rights at an average grant price of $16.45, average cumulative distributions of $4.67, ii) 0.5 million vested rights at an average grant price of $9.53, average cumulative distributions of $2.91 and a five day weighted average closing price of $18.95 and iii) 0.7 million vested rights at an average grant price of $13.49, average cumulative distributions of $1.44 and a ten day weighted average price of $18.83.

The total amount expensed under these plans was as follows:

($000)	**2010**	2009
Market based compensation	**21,236**	4,540
Reserve value based compensation	**8,628**	540
Total	**29,864**	5,080

For the future market based component, compensation costs as at December 31, 2010 were $4.0 million, which related to 0.5 million non-vested rights with an average grant price of $9.56 and 1.3 million non-vested rights with an average grant price of $13.49. (2009 – 1.5 million non-vested rights with an average grant price of $16.33 and 1.0 million non-vested rights with an average grant price of $9.55 were $3.0 million). The cumulative provision for future performance based compensation as at December 31, 2010 was $7.0 million (2009 - $3.0 million).

13. Future Income Taxes

On December 31, 2010, the Company converted from a publicly traded income trust to a publicly traded corporation by way of a plan of arrangement (see Note 1). As a result, for the year ended December 31, 2010, the Company's future income tax recovery was calculated on the basis of it being a corporation. For the year ended December 31, 2009, the Company's future income tax recovery was calculated on the basis of it being a publicly traded income trust in accordance with legislation applicable to certain income trusts.

($000)	**2010**	2009
Earnings before income taxes	**106,051**	121,330
Statutory income tax rate	**28.00%**	29.00%
Expected income taxes	**29,694**	35,186
Increase (decrease) in income taxes from:		
Corporate income tax rate change	**367**	(25,277)
Income distributed by the Trust	**(40,123)**	(40,244)
Change in valuation allowance	**(5,968)**	(1,040)
Other	**243**	(69)
Future income tax expense (recovery)	**(15,787)**	(31,444)
Differences between tax base and reported amounts for depreciable assets	**117,940**	126,746
Financial derivative asset	**7,361**	337
Share issuance costs	**(2,872)**	(781)
Future performance based bonuses	**(1,838)**	(260)
Provision for asset retirement obligation	**(2,981)**	(2,621)
Tax assets previously under valuation allowance	**(4,968)**	-
Tax loss carry-forwards recognized	**(75)**	-
Future income taxes	**112,567**	123,421

At December 31, 2010 the Company has tax pools of approximately $884.0 million (December 31, 2009 - $676.1 million) available for deduction against future income. The Company has approximately $nil in unrecognized future income tax assets (December 31, 2009 - $6.0 million) and approximately $0.3 million in loss carryforwards (December 31, 2009 - $nil) available to reduce future taxable income.

14. Financial Instruments and Risk Management

Financial Instrument Classification and Measurement

Financial instruments of the Company carried on the Consolidated Balance Sheet are carried at amortized cost with the exception of cash 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, 2010.

The fair value of the Company's cash and financial derivative instruments are quoted in active markets. The Company 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 Company's cash 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 Company's financial instruments include cash, accounts receivable, financial derivative instruments, due from private placement, current liabilities, provision for future performance based compensation and long term debt. At December 31, 2009, the carrying value of cash 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 Company'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 Company's objectives, processes and policies for managing market risks have not changed from the previous year.

Commodity Price Risk Management

The Company is a party to certain derivative financial instruments, including fixed price contracts. The Company 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 Company 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 Company's firm commitment or forecasted transactions and the underlying basis of the instruments correlate highly with the Company'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 as at December 31, 2010	Asset as at December 31, 2009
Natural gas financial swaps - AECO	24.01 GJ (2)	2011- 2012	$5.07/GJ	Level 1	27,911	9,936

(1) Notional values as at December 31, 2010 (2) Millions of gigajoules

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
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 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, 2011	Fixed Price	5,000 GJ	$5.70/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$4.55/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$5.67/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$5.82/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
November 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$4.10/GJ
April 1, 2011 to October 31, 2011	Fixed Price	5,000 GJ	$3.50/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$6.20/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$5.00/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$5.12/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.05/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.15/GJ
November 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.50/GJ

As at December 31, 2010, the Company had committed to the future sale of 24,010,000 gigajoules (GJ) of natural gas at an average price of $5.07 per GJ or $5.93per mcf based on the historical heating value of Peyto's natural gas. Had these contracts been closed on December 31, 2010, the Company would have realized a gain in the amount of $27.9 million. If the AECO gas price on December 31, 2010 were to increase by $1/GJ, the unrealized gain on these closed contracts would change by approximately $24.0 million. An opposite change in commodity prices rates would result in an opposite impact on earnings which would have been reflected in other comprehensive income.

Subsequent to December 31, 2010 the Company entered into the following contracts:

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
April 1, 2011 to October 31, 2011	Fixed price	5,000 GJ	$3.80/GJ
April 1, 2011 to October 31, 2012	Fixed price	5,000 GJ	$4.10/GJ
April 1, 2011 to October 31, 2012	Fixed price	5,000 GJ	$4.00/GJ

Interest rate risk

The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Company 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 Company's earnings for the year ended December 31, 2010 would decrease by $4.2 million. An opposite change in interest rates will result in an opposite impact on earnings.

Credit Risk

A substantial portion of the Company'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 Company generally extends unsecured credit to purchasers, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company'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 Company has not previously experienced any material credit losses on the collection of accounts receivable. Of the Company's revenue for the year ended December 31, 2010, approximately 76% was received from five companies (20%, 18%, 17%, 11% and 10%) (December 31, 2009 – 55%, three companies (21%, 20% and 14%). Of the Company's accounts receivable for the year ended December 31, 2010, approximately 31% was receivable from three companies (11%, 10% and 10%) (December 31, 2009 – the Company had no significant accounts receivable from any one customer). 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 Company considers past due and no accounts have been written off.

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

Counterparties to financial instruments expose the Company 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 Company assesses quarterly if there should be any impairment of financial assets. At December 31, 2010, there was no impairment of any of the financial assets of the Company.

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

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

The Company'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 Company to conduct equity issues or obtain project debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to certain losses.

The following are the contractual maturities of financial liabilities as at December 31, 2010:

($000s)	**<1 Year**	**1-2 Years**	**2-5 Years**	**Thereafter**
Accounts payable and accrued liabilities	113,592			
Distributions payable	15,825			
Provision for future market and reserves based bonus	5,567	1,452		
Long-term debt[1]		355,000		

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

15. Capital Disclosures

The Company'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 Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of its underlying assets. The Company considers its capital structure to include Shareholders' equity, debt and working capital. To maintain or adjust the capital structure, the Company may from time to time, issue common shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels. The Company 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 Company 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 Company is not subject to any external financial covenants.

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

($000s)	**December 31, 2010**	December 31, 2009
Shareholders’ equity	**838,646**	612,483
Long-term debt	**355,000**	435,000
Working capital deficit (surplus) (1)	**30,264**	(1,822)
	1,223,910	1,045,661

(1)Current assets less current liabilities (includes unrealized hedging asset of $25.2 million (2009 - $8.7 million))

16. Supplemental Cash Flow Information

Changes in non-cash working capital balances

($000)	**2010**	**2009**
Accounts receivable	**2,429**	7,357
Due from private placement	**(9,695)**	-
Prepaid expenses	**507**	(420)
Accounts payable and accrued liabilities	**57,703**	7,035
Distributions payable	**2,035**	(2,098)
Provision for future performance based compensation	**3,977**	3,042
	56,956	14,916
Attributable to operating activities	**22,297**	4,060
Attributable to financing activities	**(7,660)**	(2,098)
Attributable to investing activities	**42,319**	12,903
	56,956	14,916

	2010	**2009**
Cash interest paid during the year	**20,057**	16,527
Cash taxes paid during the year	**-**	-

17. Contingencies and Commitments

Following is a summary of the Company’s commitments related to operating leases as at December 31, 2010. The Company has no other contractual obligations or commitments as at December 31, 2010.

($000)	**December 31, 2010**
2011	1,043
2012	1,043
2013	1,043
2014	1,043
	4,172

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 Company's financial position or results of operations.

18. Related Party Transactions

An officer and director of the Company is a partner of a law firm that provides legal services to the Company. The fees charged are based on standard rates and time spent on matters pertaining to the Company and its subsidiaries. For the year ended December 31, 2010, legal fees totaled $1.4 million (2009 - $0.6 million). As at December 31, 2010, an amount due to this firm of $1.3 million was included in accounts payable (2009 - $0.5 million).

During the year ended December 31, 2010, a private company controlled by a director of the Company was paid $10,000 (2009 - $nil) for consulting services. The transaction with the related party occurred within normal course of business and has been measured at its exchange amount which is the amount of consideration established and agreed to with the related party.

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

David Thomas
Vice-President, Exploration

Stephen Chetner
Corporate Secretary

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

Auditors
Deloitte & Touche LLP

Solicitors
Burnet, Duckworth & Palmer LLP

Bankers
Bank of Montreal
Union Bank, Canada Branch
BNP Paribas (Canada)
Royal Bank of Canada
Canadian Imperial Bank of Commerce
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.TO
Toronto Stock Exchange