PEYTO

Exploration & Development Corp.

2010

Annual Report

Chairman's Message

This past year marks Peyto's twelfth year in business, and what a profitable 12 years it has been. In a relatively short period of time, our team has built one of the highest quality energy assets in North America. Most importantly, our company has been built profitably, through the drill bit; we have utilized our technical skills to exploit the natural resources in our basin, generating real returns for our shareholders. Our entrepreneurial culture and common sense approach to business is unique. As a founder, a director and a shareholder, I'm very pleased with what our team has accomplished in 2010 and equally excited about what the future holds for our company.

Twelve years ago I became President of a new company we named Peyto Exploration and Development Corp., after Bill Peyto, a prospector and mountain guide in Alberta during the late 1800s. We had no production, no land and no infrastructure in the Deep Basin. Our shares were trading at less than 5 cents. We started with some ideas to develop a liquid rich gas resource play in the Deep Basin. We were the original resource company. When I look at the assets we have managed to build since that humble start, I'm truly amazed. Today we are the dominant player in the Deep Basin. I'm confident there isn't another company in our area that compares when you consider the quality of our land, infrastructure, production and people.

In last year's message to shareholders, I mentioned that we had shifted gears from vertical to horizontal wellbores. I mentioned that we were seeing impressive results and that we believed strongly that this new approach coupled with our high quality assets would play a significant role in generating superior returns for investors in coming years. Since that message, we have drilled 59 horizontal wells and have seen our production climb from 21,000 boe/d at this time last year to a current rate of approximately 32,000 boe/d. I'm not aware of another company that comes even close to this level of profitable growth in 2010.

Many companies in our industry try to confuse investors when they talk about production growth. When you look closer and do the math, you quickly discover they are talking in gross numbers, before adjusting for new debt or equity issued to achieve their so-called growth. In many cases, companies touting huge growth actually shrank on a per share basis. Unfortunately, this has been going on for years in our industry. I recall presenting at a major energy conference in Calgary back in June 2002. Two other CEOs had just delivered presentations in which they claimed huge growth numbers. They were outraged when, minutes later, I showed actual results for their companies and Peyto on a per share basis; my presentation completely contradicted what they had just told the audience. I decided that would be the last time I attended the conference as there was just too much noise for investors to really hear the true stories.

Companies have a responsibility to communicate to their owners honestly and shareholders should not have to dig deep just to find out how their share of the production, reserves and cash flow has performed. At Peyto we have a long history of treating our shareholders as partners and communicating with them openly and honestly.

I am proud to say that we delivered strong production per share growth of 28% from Q4 2009 to Q4 2010. When you adjust for the change in debt this growth is an even more impressive 40%. This kind of strong growth per share translates into real wealth creation for investors. Peyto delivered a total return of 42% in 2010. Over our 12 year history, the total compound return is an unparalleled 95% per annum. In simple terms, $1,000 invested into Peyto back in 1998 would be worth $400,000 today. These incredible returns are a direct reflection of the industry-leading results our people have delivered over the past 12 years.

Despite this past success, the quantity and value of our future opportunities has never been greater than it is today. On that note, I read an analyst's comments the other day about our 2010 reserves. He cautioned that the amount of undeveloped reserves that was being booked by companies today, including Peyto, was growing as a percentage of the total. His caution may have been warranted for the other companies he covered, however, our 12 year history could not offer clearer evidence that his comment with respect to Peyto was without merit. The analyst chose to conveniently ignore the fact that Peyto has a 12 year history of building production, reserves and cashflow, where before there had been none. There is not a single company in the Deep Basin today that has drilled its way to the top the way Peyto has.

In closing, a word of caution about what I see as an ongoing threat to the integrity of our energy sector—the way in which some companies continue to mislead the investment community. I discussed how certain companies report growth in an incomplete manner. Investors should also be wary of companies that promote large purchases of land but provide no reliable information on whether the land is truly prospective, the amount of capital required to develop reserves or whether it can even be done economically. They want investors to believe the biggest challenge is getting the land and after that it's as easy as shooting fish in a barrel. Be equally cautious about companies that press release peak flow rates from short term production tests leaving out any meaningful information on how the well will actually perform. At times, it seems like the Wild West is alive and kicking with yahoos on every corner selling snake oil to unwitting investors. This means it is more important than ever for investors to do their homework and differentiate between the real profitable businesses and the ones who see the investor as their opportunity.

Everyone associated with Peyto over the past 12 years can be proud of the fact that we have never communicated to investors in that manner. Those looking to invest in an energy company with a clear and transparent track record of success, with insiders who eat their own cooking, with a honest and talented team of individuals working every day on their behalf and with assets second to none, need look no further than Peyto.

Don T. Gray
Chairman of the Board

Report from the President

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%*

	3 Months Ended December 31		12 Months Ended December 31	
($000)	**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.

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

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 Exploration & Development Corp. ("Peyto" or the "Company", successor issuer to Peyto Energy Trust, the "Trust") for the years ended December 31, 2010 and 2009. 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, 2011. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com.

Corporate Conversion

Effective December 31, 2010, the Company completed a plan of arrangement (the "2010 Arrangement") pursuant to which it acquired all of the assets and assumed all of the liabilities, respectively, of the Trust. Prior to completion of the 2010 Arrangement, the Trust was a reporting issuer in all provinces of Canada and the Trust Units were listed for trading on the TSX. Following completion of the 2010 Arrangement, the Common Shares were listed for trading on the TSX concurrent with the delisting of the Trust Units, the Trust ceased to be a reporting issuer and Peyto became a reporting issuer as successor to the Trust. Pursuant to the terms of the 2010 Arrangement, former holders of Trust Units received one Common Share for each one Trust Unit held. The former Unitholders received an aggregate of 131,875,382 Common Shares in exchange for all of the outstanding Trust Units. The conversion of the Trust to a corporate structure was intended to be a tax deferred transaction for Canadian and United States federal income tax purposes. For more information, please refer to the Information Circular dated November 5, 2010 which is available on Peyto's website at www.peyto.com or on SEDAR at www.sedar.com.

There were no changes in Peyto's underlying operations associated with the 2010 Arrangement. The consolidated financial statements and related financial information have been prepared on a continuity of interest basis, which recognizes Peyto as the successor entity and accordingly all comparative information presented for the preconversion period is that of the Trust. For the convenience of the reader, when discussing prior periods this MD&A refers to common shares, shareholders and dividends although for the pre-conversion period such items were trust units, unitholders and distributions, respectively.

Certain information set forth in this MD&A, including management's assessment of the Company'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 company involved in the development and production of natural gas in Alberta's deep basin. As at December 31, 2010, the total Proved plus Probable reserves were 1,558 billion cubic feet equivalent (256.7 million barrels of oil equivalent) as evaluated by the independent petroleum engineers. Production is weighted approximately 86% to natural gas and 14% to 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 share 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.
- Build an asset base which is made up of high quality long life natural gas reserves.
- Balance dividends to shareholders and funding for the capital program with cash flow and available bank lines.

Operating results over the last twelve years indicate that these principles have been successfully implemented. This business model makes Peyto a truly unique energy company.

ANNUAL FINANCIAL INFORMATION

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

Year Ended December 31 ($000 except per share amounts)	**2010**	2009	2008
Total revenue (before royalties)	**319,426**	273,517	418,885
Funds from operations	**234,077**	202,699	286,907
Per share – basic and diluted	**1.94**	1.83	2.71
Earnings	**121,838**	152,774	179,397
Per share – basic and diluted	**1.01**	1.38	1.69
Total assets	**1,454,575**	1,254,113	1,280,246
Total long-term debt	**355,000**	435,000	500,000
Distributions per unit	**1.44**	1.47	1.76

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 share calculations of funds from operations to be key measures as they demonstrate the Company's ability to generate the cash necessary to pay dividends, 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 Peyto'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.

QUARTERLY FINANCIAL INFORMATION

	2010				**2009**			
($000 except per share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenue (net of royalties)	**80,921**	69,650	64,649	70,801	64,761	56,353	56,598	70,133
Funds from operations	**66,359**	56,743	52,415	58,559	53,302	45,263	45,527	58,607
Per share – basic and diluted	**0.53**	0.47	0.44	0.51	0.46	0.39	0.43	0.55
Earnings	**27,700**	32,567	24,696	36,874	33,035	26,976	29,189	63,574
Per share – basic and diluted	**0.22**	0.27	0.21	0.32	0.28	0.24	0.28	0.60
Distributions	**46,299**	43,875	43,622	41,470	41,371	41,371	39,211	41,309
Per unit – basic and diluted	**0.36**	0.36	0.36	0.36	0.36	0.36	0.37	0.39

RESULTS OF OPERATIONS

Production

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2010	2009	**2010**	2009
Natural gas (mmcf/d)	**148.6**	95.5	**122.0**	92.7
Oil & natural gas liquids (bbl/d)	**3,439**	3,222	**3,389**	3,027
Barrels of oil equivalent (boe/d)	**28,197**	19,133	**23,728**	18,481
Thousand cubic feet equivalent (mmcfe/d)	**169.2**	114.8	**142.4**	110.9

Natural gas production averaged 148.6 mmcf/d in the fourth quarter of 2010, 56% higher than the 95.5 mmcf/d reported for the same period in 2009. Oil and natural gas liquids production averaged 3,439 bbl/d, up from 3,222 bbl/d reported in the prior year. Production for the year increased 28% from 110.9 mmcfe/d to 142.4 mmcfe/d (18,481 boe/d to 23,728 boe/d). The production increases are attributable to Peyto's increased capital program and resulting production additions.

Commodity Prices

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2010	2009	**2010**	2009
Natural gas ($/mcf)	**3.89**	4.79	**4.36**	4.58
Hedging – gas ($/mcf)	**1.04**	1.38	**1.00**	1.86
Natural gas – after hedging ($/mcf)	**4.93**	6.17	**5.36**	6.44
Oil and natural gas liquids ($/bbl)	**67.06**	60.77	**65.31**	50.18
Total Hedging ($/mcfe)	**0.91**	1.14	**0.85**	1.56
Total Hedging ($/boe)	**5.48**	6.86	**5.12**	9.34

Peyto's natural gas price, before hedging gains, averaged $3.89/mcf during the fourth quarter of 2010, a 19% decrease from $4.79/mcf reported for the equivalent period in 2009. Oil and natural gas liquids prices averaged $67.06/bbl, an increase of 10% from $60.77/bbl a year earlier. Average natural gas price for the year was down 5% at $4.36/mcf while oil and natural gas liquids prices were up 30% at $65.31/bbl compared to 2009. Hedging activity accounted for 16% of Peyto's achieved price for the fourth quarter and 14% of the annual price.

Revenue

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2010**	2009	**2010**	2009
Natural gas	**53,196**	42,127	**194,293**	155,072
Oil and natural gas liquids	**21,216**	18,013	**80,788**	55,458
Hedging gain	**14,221**	12,078	**44,345**	62,987
Total revenue	**88,633**	72,218	**319,426**	273,517

For the three months ended December 31, 2010, gross revenue increased 23% to $88.6 million from $72.2 million for the equivalent period in 2009. Revenue for 2010 increased 17% to $319.4 million from $273.5 million in 2009. The increase in revenue for the period was a result of increased production volumes and higher realized oil and NGL prices offset by lower realized natural gas prices as detailed in the following table:

	Three Months ended Dec. 31			Twelve Months ended Dec. 31		
	2010	2009	**$million**	2010	2009	**$million**
Total Revenue, December 31, 2009			**72.2**			**273.5**
Revenue change due to:						
Natural gas						
Volume (mmcf)	13,667	8,783	**30.1**	44,541	33,842	**68.9**
Price ($/mcf)	$4.93	$6.17	**(16.9)**	$5.36	$6.44	**(48.1)**
Oil & NGL						
Volume (mbbl)	316	296	**1.2**	1,237	1,105	**6.5**
Price ($/bbl)	$67.06	$60.77	**2.0**	$65.31	$50.18	**18.6**
Total Revenue, December 31, 2010			**88.6**			**319.4**

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 on the Crown's share of production based on a monthly established Alberta Reference Price. The Alberta Reference Price is a monthly weighted average price of gas consumed in Alberta and gas exported from Alberta reduced for transportation and marketing allowances.

($000 except per share amounts)	Three Months ended Dec. 31 **2010**	2009	Twelve Months ended Dec. 31 **2010**	2009
Royalties	**7,712**	7,457	**33,405**	25,671
% of sales before hedging	**10**	12	**12**	12
% of sales after hedging	**9**	10	**10**	9
$/mcfe	**0.50**	0.71	**0.64**	0.63
$/boe	**2.97**	4.24	**3.86**	3.81

For the fourth quarter of 2010, royalties averaged $0.50/mcfe or approximately 9% of Peyto's total petroleum and natural gas sales. Royalties for the year were essentially flat at $0.64/mcfe.

Substantially all of the Trust's production is in Province of Alberta. Under the Alberta Royalty Framework ("ARF") the Crown royalty rate varies with production rates and commodity prices. The royalty rate expressed as a percentage of sales revenue will fluctuate from period to period due to the fact that the Alberta Reference Price can differ significantly from the commodity prices realized by the Trust and that hedging gains and losses are not subject to royalties.

In addition to the basic underlying royalty structure (the ARF); Alberta has instituted additional features that impact the royalty paid on gas, particularly for newly drilled wells. These additional features include:

1. A drilling royalty credit program that is presently active but will terminate on March 31, 2011. Under this program credits are earned at a rate of $200 per meter of newly drilled well depth and can be applied with certain limitations to the earning company's corporate royalty bill. For the twelve months ending December 31, 2010 $18.2 million in Alberta drilling credits have been recognized as a reduction to capital spending,
2. A one year flat 5% royalty period (18 months for horizontal wells) for each new well but capped at a cumulative production level of 500 MMcf for each new well, and
3. A Natural Gas Deep Drilling Holiday program that provides a royalty holiday value for new wells based on meterage drilled. This holiday feature further reduces the royalty for new wells to a minimum of 5% for a maximum 5 year period from on-stream date. This benefit sequentially follows the benefit under point (2) above.

From the combination of these royalty programs, Peyto has experienced a decrease in overall corporate royalty rates. This, in part, can be attributed to a decline in commodity prices and the dependence of royalty rates on commodity prices. In its 12 year history, Peyto has invested over $1.9 billion in capital projects, found and developed 1.2 TCFe of gas reserves, and paid over $532 million in royalties.

Operating Costs & Transportation

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 production reduces operating expenses.

	Three Months ended Dec. 31 **2010**	2009	Twelve Months ended Dec. 31 **2010**	2009
Operating costs ($000)				
Field expenses	**7,395**	6,525	**28,960**	27,487
Processing and gathering income	**(2,614)**	(2,528)	**(10,545)**	(10,751)
Total operating costs	**4,781**	3,997	**18,415**	16,736
$/mcfe	**0.31**	0.38	**0.35**	0.41
$/boe	**1.84**	2.27	**2.13**	2.48
Transportation	**2,157**	1,172	**6,954**	4,541
$/mcfe	**0.14**	0.11	**0.13**	0.11
$/boe	**0.83**	0.67	**0.80**	0.67

Operating costs were $4.8 million in the fourth quarter of 2010 compared to $4.0 million for the equivalent period in 2009. On a unit-of-production basis, operating costs averaged $0.31/mcfe in the fourth quarter of 2010 compared to $0.38/mcfe for the equivalent period in 2009. Operating costs for the year averaged $0.35/mcfe in 2010 compared to $0.41/mcfe in 2009. Transportation expense increased on a per mcfe basis due to an increase in pipeline tariffs effective January 1, 2010.

General and Administrative Expenses

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2010	2009	**2010**	2009
G&A expenses ($000)	**3,819**	2,445	**11,063**	9,797
Overhead recoveries	**(1,735)**	(813)	**(4,545)**	(2,505)
Net G&A expenses	**2,084**	1,632	**6,518**	7,292
$/mcfe	**0.13**	0.15	**0.12**	0.18
$/boe	**0.80**	0.93	**0.75**	1.08

For the fourth quarter, general and administrative expenses before overhead recoveries were up 56% over the same quarter of 2009 and 13% on an annual basis due primarily to costs of $0.7 million incurred in 2010 associated with the 2010 Arrangement. Capital overhead recoveries increased 113% for the fourth quarter from $0.8 million to $1.7 million and 81% on an annual basis as a result of the increased capital program in 2010.

Interest Expense

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2010	2009	**2010**	2009
Interest expense ($000)	**5,540**	4,608	**20,057**	16,527
$/mcfe	**0.36**	0.44	**0.39**	0.41
$/boe	**2.14**	2.62	**2.32**	2.45
Average interest rate	**5.0%**	4.2%	**4.6%**	3.5%

Fourth quarter 2010 interest expense was $5.5 million or $0.36/mcfe compared to $4.6 million or $0.44/mcfe for the equivalent period in 2009. 2010 interest expense was $20.1 million or $0.39/mcfe compared to $16.5 million or $0.41/mcfe a year earlier due to an increase in interest rates.

Netbacks

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($/mcfe)	**2010**	2009	**2010**	2009
Gross Sale Price	**4.79**	5.70	**5.29**	5.19
Hedging gain	**0.91**	1.14	**0.85**	1.56
Net Sale Price	**5.70**	6.84	**6.14**	6.75
Less: Royalties	**0.50**	0.71	**0.64**	0.63
Operating costs	**0.31**	0.38	**0.35**	0.41
Transportation	**0.14**	0.11	**0.13**	0.11
Field netback	**4.75**	5.64	**5.02**	5.60
General and administrative	**0.13**	0.15	**0.12**	0.18
Interest on long-term debt	**0.36**	0.44	**0.39**	0.41
Cash netback ($/mcfe)	**4.26**	5.05	**4.51**	5.01
Cash netback ($/boe)	**25.58**	30.31	**27.03**	30.06

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 Company'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 2010 provision for depletion, depreciation and accretion totaled $94.2 million compared to $73.3 million in 2009. On a unit-of-production basis, depletion, depreciation and accretion costs for 2010 averaged $1.81/mcfe; the same as in 2009.

Income Taxes

The current provision for future income tax recovery is $15.8 million (2009 – $31.4 million). Resource pools are generated from the capital program, which are available to offset current and future income tax liabilities. 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. 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. This recovery is attributable to the following items: i) distribution of taxable income of the Trust in excess of net income, decreasing the required tax pool claims, ii) recognition of the value of certain tax assets not previously recognized as they could not be used under the trust structure, and iii) reduction in corporate income tax rates.

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.

MARKETING

Commodity Price Risk Management

The Company is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Company 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 executed with financial institutions that are members of Peyto's loan syndicate. During 2010, a realized hedging gain of $44.3 million was recorded as compared to $63.0 million in 2009. A summary of contracts outstanding in respect of the hedging activities are as follows:

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 Trust 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 Trust would have realized a gain in the amount of $27.9 million.

Subsequent to December 31, 2010 the Trust entered into the following contract:

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

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 Company has no control. Low operating costs and a long reserve life reduce Peyto's sensitivity to changes in commodity prices.

Currency Risk Management
The Company 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 Company 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 31, 2010, 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 $1.0 million per quarter or $4.2 million per annum. Average debt outstanding for the fourth quarter of 2010 was $438.6 million.

LIQUIDITY AND CAPITAL RESOURCES

Funds from operations is reconciled to cash flows from operating activities below:

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**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 (recovery of) performance based compensation	**(7,456)**	1,266	**3,978**	3,042
Market and reserve value 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**	0.46	**1.94**	1.83

For the fourth quarter ended December 31, 2010, funds from operations totaled $66.4 million or $0.53 per share, as compared to $53.3 million, or $0.46 per share during the same quarter in 2009. Funds from operation for the year was up 13% to $234.1 million. Peyto's policy is to balance dividends to shareholders and funding for a capital program with cash flow and available bank lines. Earnings and cash flow are 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
Peyto 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 Peyto, 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, 2010 was 5.0% (2009 – 4.2%). Outstanding amounts on this facility will bear interest at rates determined by Peyto's debt to cash flow ratio that range from prime plus 1.25% to prime plus 2.75% for debt to earnings

before interest, taxes, depreciation, depletion and amortization (EBITDA) ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank.

At December 31, 2010, $355 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, 2010, the working capital deficit was $30.3 million (including a non-cash current asset for an unrealized mark to market future hedging gain of $25.2 million).

Peyto believes funds generated from operations, together with borrowings under the credit facility will be sufficient to maintain dividends, finance current operations, and fund the planned capital expenditure program of $300 to $325 million for 2011. The total amount of capital invested in 2011 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 Company. 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 Company. Net debt is reconciled below to long-term debt which is the most directly comparable GAAP measure:

($000)	**As at December 31, 2010**	As at December 31, 2009
Long-term debt	**355,000**	435,000
Current liabilities	**134,984**	71,681
Current assets	**(104,720)**	(73,503)
Financial derivative instruments	**25,247**	8,683
Provision for future performance based compensation	**(5,567)**	(2,001)
Net debt	**404,944**	439,860

Capital
Authorized: Unlimited number of voting common shares

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	(131,875,382)	(754,493)
Balance, December 31, 2010	**-**	**-**

Issued and Outstanding

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

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 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.

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 percent 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.

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

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

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.

Shares to be Issued
On December 31, 2010 Peyto completed a private placement of 655,581 common shares to employees and consultants for net proceeds of $12.4 million ($18.95 per unit). These 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.

Performance Based Compensation
The Company 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 dividends, 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 $8.6 million was recorded for the year ended December 31, 2010.

($millions except share values)	2010	2009	**Change**
Net present value of proved producing reserves @ 8% based on constant InSite 2011 price forecast	1,254.0	1,178.0	
Net debt before performance based compensation	(392.4)	(439.9)	
2010 distributions, G&A and interest		(201.8)	
Net value	861.6	536.3	
Shares/units outstanding	131.875	115.117	
Net value per 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**

Under the market based component, rights vesting over three years 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 for the year ended 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. The cumulative provision as at December 31, 2010 was $7.0 million.

Capital Expenditures

Net capital expenditures for the fourth quarter of 2010 totaled $110.6 million. Exploration and development related activity net of drilling royalty credits represented $82.6 million (75% of total), while expenditures on facilities, gathering systems and equipment totaled $14.8 million (13% of total) and land, seismic and acquisitions totaled $13.2 million (12% of total). Capital expenditures of $261.5 million for 2010 were 259% higher than 2009 capital expenditures. 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

Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
	2010	2009	**2010**	2009
Funds from operations ($000)	**66,359**	53,302	**234,077**	202,699
Total distributions ($000)	**46,299**	41,371	**175,268**	163,263
Total distributions per unit ($)	**0.36**	0.36	**1.44**	1.47
Payout ratio (%)	**70**	78	**75**	81
Total cash distributions (net of DRIP) ($000)	**40,900**	41,371	**162,736**	163,263
Payout ratio (net of DRIP) (%)	**62**	78	**70**	81

Peyto's policy is to balance dividends to shareholders 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 (dividends declared divided by funds from operations) to achieve the desired dividends while maintaining an appropriate capital structure.

Retained Earnings and Distributions

	Three Months ended Dec. 31		Twelve Months ended Dec. 31	
($000)	**2010**	2009	**2010**	2009
Opening retained earnings (before distributions)	**1,166,347**	1,039,174	**1,072,209**	919,435
Earnings for the period	**27,700**	33,035	**121,838**	152,774
Total retained earnings (before distributions)	**1,194,047**	1,072,209	**1,194,047**	1,072,209
Total accumulated distributions	**(1,147,728)**	(972,460)	**(1,147,728)**	(972,460)
Retained earnings (after distributions)	**46,319**	99,749	**46,319**	99,749

Since inception, Peyto has accumulated earnings of $1.2 billion and distributed $1.1 billion to unitholders while a trust.

Taxation of Distributions and Dividends

Distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the trust units held. Effective January 1, 2011, Peyto will pay dividends to its shareholders. Dividends taxed differently than distributions of the Trust in that dividends do not comprise a return of capital and thus are fully taxable.

For 2010, Peyto paid distributions to unitholders in the amount of $175.3 million (2009 - $163.3 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit [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 14, 2011	$0.12

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

Contractual Obligations

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

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

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.

RISK MANAGEMENT

Investors who purchase shares are participating in the total returns from a portfolio of western Canadian natural gas producing properties. As such, the total returns earned by investors and the value of the shares are subject to numerous risks inherent in the oil and natural gas industry.

Expected returns depend 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 dividends to shareholders and the value of the shares. 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 shareholders.

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 Company against certain potential losses.

The value of Peyto's shares 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 counterparties.

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 Company 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 Company 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 Company'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 Company is made known to the Company'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 Company 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 Company's disclosure controls and procedures at the year end of the Company and have concluded that the Company's disclosure controls and procedures are effective at the financial period end of the Company for the foregoing purposes.

Internal Control over Financial Reporting
The Company'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 Company'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 Company's internal control over financial reporting at the financial period end of the Company and concluded that the Company's internal control over financial reporting is effective, at the financial period end of the Company, for the foregoing purpose.

The Company is required to disclose herein any change in the Company's internal control over financial reporting that occurred during the period ended December 31, 2010 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting. No material changes in the Company's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

It should be noted that a control system, including the Company'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 Company'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 Company's reserves will likely vary from estimates, and such variances may be material.

The Company's estimated quantities of proved and probable reserves at December 31, 2010 were audited by independent petroleum engineers InSite Petroleum Consultants Ltd. InSite has been evaluating reserves in this area and for Peyto for 12 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 February 2011. A quarterly provision for the reserve value based compensation is calculated using estimated proved producing reserve additions adjusted for changes in debt, equity and dividends. 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 Company'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 Company has not applied a new primary source of GAAP that has been issued, but is not effective, the Company 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

International Financial Reporting Standards
The Accounting Standards Board (AcSB) confirmed in February 2008 that International Financial Reporting Standards (IFRS) will replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on or after January 1, 2011. Accordingly, the conversion from Canadian GAAP to IFRS will be applicable to the Trust's reporting for the first quarter of 2011 for which current and comparative information will be prepared under IFRS.

Peyto's project consists of three key phases:

- Scoping and diagnostic phase – this phase involves performing a high level impact analysis to identify areas that may be affected by the transition to IFRS. The results of this analysis are priority ranked according to complexity and the amount of time required assessing the impact of changes in transitioning to IFRS.

- Impact analysis and evaluation phase – during this phase, items identified in the diagnostic phase are addressed according to the priority levels assigned to them. This phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are further investigated to assess whether there may be a broader impact to Peyto's debt agreements, compensation arrangements or management reporting systems. The conclusion of the impact analysis and evaluation phase will require the Audit Committee of the Board of Directors to review all accounting policy choices as proposed by management.

- Financial implementation phase – involves implementation of all changes approved in the impact analysis phase and will include changes to information systems, business processes, modification of agreements and training of all staff who are impacted by the conversion.

Peyto has effectively completed all phases of its IFRS transition project and continues to review its draft IFRS financial statements and disclosures for completeness and quality assurance. The Audit Committee has reviewed all accounting policy choices proposed by management.

First Time Adoption of IFRS

Most adjustments required on transition to IFRS will be made retrospectively against opening retained earnings as of the date of the first comparative balance sheet presented, based on standards applicable at that time. IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Management has analyzed the various accounting policy choices available under IFRS 1 and has implemented those determined to be the most appropriate for Peyto. The following IFRS 1 exemptions have been applied in the IFRS opening balance sheet:

- Property Plant and Equipment ("PP&E") – IFRS 1 provides the option to retrospectively restate PP&E assets at their deemed cost being the Canadian GAAP net book value assigned to these assets as at the date of transition, January 1, 2010 rather than restating historical cost. Peyto has determined that it has one cash generating unit (CGU). The number of CGUs could change in the future as a result of significant acquisitions in other geographical areas or some other significant change in the nature of Peyto's operations.

- Business combinations – IFRS 1 provides an optional exemption to the requirement to retrospectively restate any business combinations recorded previously under Canadian GAAP. This exemption is not applicable as Peyto had no significant business combinations recorded previously under Canadian GAAP.

The following is a listing of key areas where accounting policies differ and where accounting policy decisions are necessary that will impact our reported financial position and results of operations:

- Re-classification of Exploration and Evaluation ("E&E") expenditures from PP&E – Upon transition to IFRS, Peyto will reclassify any E&E expenditures that are currently included in PP&E on the Consolidated Balance Sheet. E&E assets will not be depleted and must be assessed for impairment when indicators suggest the possibility of impairment. Peyto does not have any significant E&E assets.

- Calculation of depletion expense for PP&E assets – Upon transition to IFRS, Peyto has the option to calculate depletion using a reserve base of proved reserves or both proved and probable reserves, as compared to the Canadian GAAP method of calculating depletion using only proved reserves. Peyto is currently assessing which method for calculating depletion will be used.

- Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations were performed at the cash generating unit level using total proved plus probable reserves. Impairment testing has been completed and no impairments were identified.

- Provisions for asset retirement costs – Under IFRS, Peyto is required to revalue its entire liability for asset retirement costs at each balance sheet date using a current liability-specific discount rate, which can generally be interpreted to mean the current risk-free rate of interest. Under Canadian GAAP, once recorded, asset retirement obligations are not adjusted for future changes in discount rates. As at January 1, 2010, Peyto's asset retirement obligations will increase $8.3 million to $18.8 million.

- Provision for future market based compensation - Peyto issues stock-based compensation awards which are valued at intrinsic value under Canadian GAAP. Upon the adoption of IFRS, this liability will be restated to fair value. At

January 1, 2010, Peyto's current liability for future performance based compensation will increase $1.4 million to $3.4 million while the long term liability will not change significantly.

- Deferred income taxes - Under IFRS, entities that are subject to different tax rates on distributed and undistributed income must calculate deferred taxes using the undistributed profits rate, which is the higher of the two. Canadian GAAP requires each individual tax rate to be applied to distributed and undistributed profits, respectively. As a result of using the undistributed profits rate, Peyto will record an increase in its deferred tax liability of $71.5 million upon transition to IFRS, with the offset recorded as a reduction to retained earnings. Upon conversion to a corporation on December 31, 2010, tax rates used to calculate deferred taxes will be corporate income tax rates which will result in a deferred tax recovery of substantially all of this amount.

The following table summarizes Peyto's January 1, 2010 balance sheet under Canadian GAAP and the transitional entries required to present the opening balance sheet under IFRS. Peyto has not yet prepared a full set of annual financial statements under IFRS, therefore, amounts are unaudited.

($000)	**Canadian GAAP**	**IFRS Adjustments**	**IFRS**
Current assets	73,503	-	73,503
Long term assets	1,180,610	-	1,180,610
Total assets	1,254,113		1,254,113
Current liabilities	71,681	1,394	73,075
Long term liabilities	569,949	79,804	649,753
Equity	612,483	(81,198)	531,285
Total liabilities and equity	1,254,113		1,254,113

In addition to accounting policy differences, Peyto's transition to IFRS is expected to impact its internal controls over financial reporting, disclosure controls and procedures, information systems and certain of the Company's business activities as follows:

Internal controls over financial reporting ("ICFR") –Peyto is currently reviewing its ICFR documentation and assessing whether changes to controls are required to address accounting policy changes under IFRS. No material changes are expected as a result of the transition to IFRS.

Disclosure controls and procedures – Peyto has assessed the impact of transition to IFRS on its disclosure controls and procedures and has not identified any material changes required in its control environment. It is expected that there will be increased note disclosure around certain financial statement items than what is currently required under Canadian GAAP. Management is currently drafting its IFRS note disclosure in accordance with current IFRS standards and continues to monitor requirements put forth by the IASB in discussion papers and exposure drafts for future disclosure requirements. Throughout the transition process, Peyto has carefully considered its stakeholders' information requirements and will continue to ensure that adequate and timely information is provided to meet these needs.

Information systems – Peyto has assessed its systems capabilities and identified any changes required to support Canadian GAAP and IFRS reporting. Modifications have been made to track PP&E and E&E expenditures at the level required by IFRS. No significant modifications were required.

Business activities – Management has worked with its counterparties and lenders to ensure that any agreements that contain references to Canadian GAAP financial statements are modified to allow for IFRS statements. Based on the changes to Peyto's accounting policies, no issues are expected with the existing wording of debt covenants and related agreements as a result of the conversion to IFRS.

ADDITIONAL INFORMATION

Additional information relating to Peyto Exploration & Development Corp. can be found on SEDAR at www.sedar.com and www.peyto.com.

Quarterly information

	2010				2009
	Q4	Q3	Q2	Q1	Q4
Operations					
Production					
Natural gas (mcf/d)	148,551	122,717	112,422	103,934	95,467
Oil & NGLs (bbl/d)	3,439	3,322	3,465	3,330	3,222
Barrels of oil equivalent (boe/d @ 6:1)	28,197	23,775	22,202	20,653	19,133
Thousand cubic feet equivalent (mcfe/d @ 6:1)	169,184	142,651	133,211	123,916	114,798
Average product prices					
Natural gas ($/mcf)	4.93	5.16	5.25	6.34	6.17
Oil & natural gas liquids ($/bbl)	67.06	59.66	65.58	68.93	60.77
$/MCFE					
Average sale price ($/mcfe)	5.70	5.83	6.14	7.17	6.84
Average royalties paid ($/mcfe)	0.50	0.52	0.81	0.82	0.71
Average operating expenses ($/mcfe)	0.31	0.34	0.38	0.41	0.38
Average transportation costs ($/mcfe)	0.14	0.14	0.13	0.13	0.11
Field netback ($/mcfe)	4.75	4.83	4.82	5.81	5.64
General & administrative expense ($/mcfe)	0.13	0.12	0.09	0.16	0.15
Interest expense ($/mcfe)	0.36	0.39	0.41	0.40	0.44
Cash netback ($/mcfe)	4.26	4.32	4.32	5.25	5.05
Financial ($000 except per share)					
Revenue	88,633	76,450	74,370	79,974	72,218
Royalties	7,712	6,800	9,721	9,173	7,457
Funds from operations	66,359	56,743	52,415	58,559	53,302
Funds from operations per share	0.53	0.47	0.44	0.51	0.46
Total distributions	46,299	43,875	43,622	41,470	41,371
Total distributions per share	0.36	0.36	0.36	0.36	0.36
Payout ratio	70%	77%	83%	71%	78%
Earnings	27,700	32,567	24,696	36,874	33,035
Earnings per diluted share	0.22	0.27	0.21	0.32	0.28
Capital expenditures	110,561	64,123	37,439	49,361	26,307
Weighted average shares outstanding	125,726,450	121,765,712	119,419,799	115,153,667	114,920,194

Deloitte.

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Peyto Exploration & Development Corp.:

We have audited the accompanying consolidated financial statements of Peyto Exploration & Development Corp., which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of earnings, comprehensive income, retained earnings and accumulated other comprehensive income and cash flows for the years then ended, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Peyto Exploration & Development Corp. as at December 31, 2010 and 2009, and the results of 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
March 8, 2011

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

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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

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Solicitors
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BNP Paribas (Canada)
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