PEYTO

Exploration & Development Corp.

2

Interim Report
for the six months ended June 30, 2011

Highlights

	Three Months ended June 30		%	Six Months ended June 30		%
	2011	2010	Change	**2011**	2010	Change
Operations						
Production						
Natural gas (mcf/d)	**183,790**	112,422	*63*	**175,297**	108,202	*62*
Oil & NGLs (bbl/d)	**3,811**	3,465	*10*	**3,779**	3,398	*11*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**206,657**	133,211	*55*	**197,970**	128,589	*54*
Barrels of oil equivalent (boe/d @ 6:1)	**34,443**	22,202	*55*	**32,995**	21,432	*54*
Product prices						
Natural gas ($/mcf)	**4.43**	5.25	*(1*	**4.66**	5.77	*(1*
Oil & NGLs ($/bbl)	**84.06**	65.58	*28*	**80.18**	67.21	*19*
Operating expenses ($/mcfe)	**0.32**	0.38	*(1*	**0.35**	0.39	*(1*
Transportation ($/mcfe)	**0.13**	0.13	-	**0.13**	0.13	-
Field netback ($/mcfe)	**4.41**	4.82	*(9)*	**4.57**	5.30	*(1*
General & administrative expenses ($/mcfe)	**0.07**	0.08	*(1*	**0.08**	0.11	*(2*
Interest expense ($/mcfe)	**0.24**	0.41	*(4*	**0.25**	0.40	*(3*
Financial ($000, except per share)						
Revenue	**103,193**	74,370	*39*	**202,770**	154,344	*31*
Royalties	**12,007**	9,721	*24*	**21,929**	18,894	*16*
Funds from operations	**77,010**	52,565	*63*	**151,706**	111,414	*62*
Funds from operations per share	**0.58**	0.44	*32*	**1.14**	0.95	*20*
Total dividends	**23,951**	43,622	*(4*	**47,872**	85,093	*(4*
Total dividends per share	**0.18**	0.36	*(5*	**0.36**	0.72	*(5*
Payout ratio	**31**	83	*(6*	**32**	77	*(5*
Earnings	**32,718**	30,384	*8*	**64,406**	71,012	*(9)*
Earnings per diluted share	**0.25**	0.25	*(4)*	**0.49**	0.61	*(2*
Capital expenditures	**69,017**	37,590	*84*	**172,803**	87,240	*98*
Weighted average trust units outstanding	**133,061,301**	119,419,799	*11*	**132,900,079**	117,298,518	*13*
As at June 30						
Net debt (before future compensation expense and unrealized hedging gains)				**474,008**	417,854	*13*
Shareholders' equity				**859,205**	619,174	*39*
Total assets				**1,576,618**	1,329,323	*19*

	Three Months ended June 30		Six Months ended June 30	
($000)	**2011**	2010	**2011**	2010
Cash flows from operating activities	**81,831**	56,07	**124,718**	108,746
Change in non-cash working capital	**(7,169)**	(6,59	**20,416**	(1,229)
Change in provision for performance based	**2,348**	3,090	**6,572**	3,897
Funds from operations	**77,010**	52,56	**151,706**	111,414
Funds from operations per unit	**0.58**	0.44	**1.14**	0.95

(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 International Financial Reporting Standards ("IFRS") and does not have a standardized meaning prescribed by IFRS. 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 IFRS. Funds from operations cannot be assured and future dividends may vary.

Report from the president

Peyto Exploration & Development Corp. ("Peyto") is pleased to present its operating and financial results for the second quarter of the 2011 fiscal year. Production growth of 42% per share was achieved over Q2 2010, while at the same time operating margins of 75%(1) and profit margins of 32%(2) were generated. Second quarter 2011 highlights include:

- Company production has now doubled over the past 24 months from 17,600 boe/d in June of 2009 to 34,900 boe/d in June of 2011, with a capital investment equivalent to 95% of funds from operations for this period. All of this growth was achieved with the drill bit through organic development of Peyto's internally generated ideas.

- Second quarter production grew from 133 MMcfe/d (22,202 boe/d) in 2010 to 207 MMcfe/d (34,443 boe/d) in 2011, resulting from the successful development of Peyto's liquids rich, Deep Basin gas plays. This equates to a 42% increase per share, a 55% increase on an absolute basis, and a 50% increase in production per share, debt adjusted(3). This is the seventh consecutive quarter of production per share growth.

- Funds from operations ("FFO") increased 63% to $77.0 million in Q2 2011 from $52.6 million in Q2 2010. The 11% year over year drop in realized commodity prices from $6.14/Mcfe to $5.50/Mcfe was more than offset by increased production volumes and cost reductions. FFO per share was up 32% to $0.58/share.

- Peyto's industry leading operating costs were reduced a further 16% to $0.32/Mcfe ($1.92/boe) from Q2 2010 or $0.45/Mcfe ($2.70/boe) including transportation. Cash netbacks were only 5% lower at $4.10/Mcfe ($24.60/boe), or 75% of revenue, despite the 11% reduction in commodity prices.

- Capital expenditures of $69.0 million were invested in the quarter, up 84% from $37.6 million in Q2 2010. A total of 12 gross wells were drilled during the period.

- Earnings of $32.7 million ($0.25/share) were generated in the quarter while dividends of $24.0 million ($0.18/share) were paid to shareholders, representing a payout of 31% of FFO.

Second Quarter 2011 in Review

Peyto successfully executed on its plan to "drill through break-up" in the second quarter, taking advantage of multi-well drill pads to eliminate rig moves as the melting frost caused roads to be too soft for travel. As a result, the company continued to grow its production and funds from operations during a challenging period that saw much of the industry shut down activity and even shut in production. To the end of the second quarter, Peyto had developed over 65 MMcfe/d or 11,000 boe/d of new 2011 production at capital efficiencies similar to 2010. The completion of the Wildhay plant expansion increased the company's 100% owned and operated gas plant capacity to 285 MMcf/d. An intense focus on cost control resulted in further reduction of Peyto's already industry leading operating costs and contributed to maintaining a 75% operating margin with all-in cash costs of $1.40/Mcfe. Peyto's balance sheet continued to strengthen with the debt to annualized FFO ratio dropping from 2.0 to 1.5. The strong financial and operating performance resulted in an annualized 15% Return on Equity (ROE) and 13% Return on Capital Employed (ROCE).

1. *Operating Margin is defined as Funds from Operations divided by Revenue before Royalties but including realized hedging gain/losses.*
2. *Profit Margin is defined as Net Earnings for the quarter divided by Revenue before Royalties but including realized hedging gain/losses.*
3. *Per share results are adjusted for changes in net debt and equity. Net debt is converted to equity using a June 30 share price of $21.50 for 2011 and $14.57 for 2010. 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.*

Exploration & Development

Peyto has now drilled over 85 horizontal multi-stage fractured gas wells in the Deep Basin. Overall, production results for the 2011 wells continue to meet or exceed company expectations with initial, 3 month, and 6 month sustained production rates exhibiting similar averages to the 2010 group of wells. In total, Peyto has 17 horizontal producers that now have over 12 months of production history. At the end of their first year, six were Cardium wells still producing an average of 190 boe/d (1.1 MMcfe/d), seven were Wilrich wells at an average of 280 boe/d (1.7 MMcfe/d) and four were Notikewin wells at an average of 285 boe/d (1.7 MMcfe/d). Some of Peyto's first multi-stage fractured horizontal wells are now approaching two years of producing life and are showing strong continued performance in support of their assigned ultimate recoveries.

In addition to the ongoing refinement of the horizontal multi-stage fractured well design, Peyto is proceeding with a unique enhanced liquids extraction project at its Oldman gas plant in the Sundance area. This facility addition will effectively lower the temperature of the refrigeration process from -35 C to -75 C which is expected to result in the recovery of an additional 15 barrels of natural gas liquids per MMcf of natural gas sales while only reducing the heat content of the sales gas stream by 3%. The Oldman plant is currently delivering just over 100 MMcf/d of sales gas. This project is estimated to cost less than $20 million and is expected to be operational by Q3 2012.

Capital Expenditures

In the second quarter, Peyto executed its plan to maintain a high level of drilling activity, through the traditional spring thaw period, by utilizing multi-well drilling pads to minimize rig movement when roads are too soft to travel. As a result 12 gross (10.6 net) wells were drilled, 16 gross (12.4 net) zones completed and 14 gross (11.5 net) zones brought on stream. Capital expenditures for the quarter totaled $69 million (net of $2.6 million in Drilling Royalty Credit adjustments), up 84% from Q2 2010, with drilling, completions and wellsite connections accounting for $32.2 million, $17.5 million and $4.7 million, respectively. In addition, Peyto continued to increase its facility capacity with expansions at Wildhay and Nosehill gas plants totaling $15.8 million in capital investment. Investments in new undeveloped land and seismic totaled $1.4 million.

All of the wells drilled in the second quarter were horizontal wells as Peyto continued to use this technique to develop the multiple prospective formations in its extensive Deep Basin inventory. Of the 12 wells drilled, 5 were in the Notikewin formation, 4 in the Wilrich, and 3 in the Cardium. With each successful well drilled, future inventory was further proven and expanded.

As of the end of Q2 2011, a total of 31 gross (26.7 net) wells have been brought on stream. Total capital invested in the first half of 2011 was $172.8 million which has resulted in 11,000 boe/d of new production at a cost of $15,700/boe/d. This level of capital efficiency compares favorably to the efficiency realized in 2010. This new production is comprised of 16% from the Cardium formation, 32% from the Notikewin, 14% from the Falher and 38% from the Wilrich.

Financial Results

A natural gas price of $4.43/Mcf and a liquids price of $84.06/bbl were realized in the second quarter which combined for a net effective sales price of $5.50/Mcfe. Cash costs of $0.64/Mcfe for royalties, $0.32/Mcfe for operating, $0.13/Mcfe for transportation, $0.07/Mcfe for G&A and $0.24/Mcfe for interest reduced this sales price to a cash netback of $4.10/Mcfe or $24.60/boe. This netback divided by the effective sales price equated to a 75% operating margin, consistent with the previous quarter but improved from the 70% margin of a year ago.

DD&A costs of $1.64/Mcfe and a provision for deferred income tax and performance based compensation reduced the cash netback of $4.10/Mcfe to earnings of $1.74/Mcfe or a 32% profit margin, consistent with both the previous quarter and previous year.

Marketing

Second quarter Alberta daily natural gas prices averaged the same as a year ago but improved slightly from the previous quarter, increasing from $3.56/GJ to $3.67/GJ. This slight improvement was driven by the onset of warmer than normal US summer weather and the expectation of less domestic production growth. Average liquids price was up 28% to $84.06/bbl as a rise in crude oil prices saw par crude postings at Edmonton average $103.60/bbl. Peyto realized gains from its previous forward sales of natural gas of $6.6 million or $0.40/Mcf in Q2 2011 versus $11.4 million or $1.11/Mcf in Q2 2010.

As at June 30, 2011, Peyto had committed to the future sale of 38,770,000 gigajoules (GJ) of natural gas at an average price of $4.31 per GJ or $5.05 per mcf (based on Peyto’s historical heat content premium). Had these contracts been closed on June 30, 2011, Peyto would have realized a gain in the amount of $18.6 million. The average future sales price of $4.31/GJ is 22% lower than last year’s price of $5.52/GJ.

Activity Update

Post break-up activity has resumed to a high level despite some weather related delays experienced through late June and early July. Daily production has recently reached the 37,000 boe/d targeted exit rate for 2011. Wells drilled in 2011 have contributed over 13,000 boe/d of this amount, up from the Q2 exit level of 11,000 boe/d.

To date, 42 gross (36.1 net) wells have been spud this year and 38 gross (32.4 net) new wells have been brought onstream. Peyto has five rigs currently drilling, four in the greater Sundance area and one in the company’s northern Cardium lands.

Outlook

Peyto continues to deliver substantial, profitable growth in production and cashflow in 2011. With a rich and deep inventory of proven opportunities, greater than at any other time in the company’s twelve year history, Peyto is well positioned to continue this trend into the future. These opportunities, coupled with a strict focus on cost control, mean Peyto is uniquely capable of not only surviving a prolonged period of depressed natural gas prices, but of generating significant and profitable growth in such an environment.

As a result of the continued high returns generated in the first half of 2011, Peyto’s Board of Directors has approved the expansion of the 2011 capital program to be between $350 and $375 million, assuming market conditions remain favourable. Based on Peyto’s internal forecasts and current strip pricing, funds from operations are expected to continue to grow faster than debt. The larger capital program results in a year-end debt to FFO ratio that is expected to remain at current levels.

The strength of Peyto’s assets and its balance sheet continue to allow the company to be opportunistic in today’s volatile business climate. Management believes the “economic moat” that surrounds Peyto’s business “fortress” is wider and deeper than ever.

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
August 10, 2011

Management's discussion and analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited condensed financial statements for the period ended June 30, 2011 and the audited consolidated financial statements of Peyto Exploration & Development Corp. ("Peyto" or the "Company", successor issuer to Peyto Energy Trust, the "Trust") for the year ended December 31, 2010. The financial statements have been prepared in accordance with the International Accounting Standards Board ("IASB") most current International Financial Reporting Standards ("IFRS") and International Accounting Standards ("IAS").

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 August 9, 2011. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com and on Peyto's website at www.peyto.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 and posted 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 ("unitholders") received one common share for each 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 of Peyto ("shareholders"), per share and dividends although for the pre-conversion period such items were trust units, unitholders, per unit 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 88% to natural gas and 12% 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.

QUARTERLY FINANCIAL INFORMATION

	2011		2010				2009	
($000 except per share amounts)	**Q2**(1)	Q1(1)	Q4(1)	Q3(1)	Q2(1)	Q1(1)	Q4(2)	Q3(2)
Total revenue (net of royalties)	**91,186**	89,655	80,921	69,650	64,649	70,801	64,761	56,353
Funds from operations	**77,010**	74,696	69,201	56,341	52,565	58,849	53,302	45,263
Per share – basic and diluted	**0.58**	0.56	0.55	0.46	0.44	0.51	0.46	0.39
Earnings	**32,718**	31,688	95,419	33,983	30,384	40,628	33,035	26,976
Per share – basic and diluted	**0.25**	0.24	0.76	0.28	0.25	0.35	0.28	0.24
Dividends	**23,951**	23,921	46,299	43,875	43,622	41,470	41,371	41,371
Per share – basic and diluted	**0.18**	0.18	0.36	0.36	0.36	0.36	0.36	0.36

(1) Results are reported in accordance with IFRS.

(2) Results are reported in accordance with previous Canadian GAAP.

Funds from Operations

“Funds from operations” is a non-IFRS 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 IFRS measure is cash flows from operating activities.

RESULTS OF OPERATIONS

Production

	Three Months ended June 30		Six Months ended June 30	
	2011	2010	**2011**	2010
Natural gas (mmcf/d)	**183.8**	112.4	**175.3**	108.2
Oil & natural gas liquids (bbl/d)	**3,811**	3,465	**3,779**	3,398
Barrels of oil equivalent (boe/d)	**34,443**	22,202	**32.995**	21,432
Thousand cubic feet equivalent (mmcfe/d)	**206.7**	133.2	**198.0**	128.6

Natural gas production averaged 183.8 mmcf/d in the second quarter of 2011, 63 percent higher than the 112.4 mmcf/d reported for the same period in 2010. Oil and natural gas liquids production averaged 3,811 bbl/d, an increase of 10 percent from 3,465 bbl/d reported in the prior year. Gas production grew more than liquids production as Peyto focused its capital program more towards deeper, leaner Wilrich and Notikewan formations rather than the richer

Cardium formation. Second quarter oil and gas production increased 55 percent from 133.2 mmcfe/d to 206.7 mmcfe/d. The production increases are attributable to Peyto's increased capital program and resulting production additions.

Commodity Prices

	Three Months ended June 30		Six Months ended June 30	
	2011	2010	**2011**	2010
Natural gas ($/mcf)	**4.03**	4.14	**4.04**	4.89
Hedging – gas ($/mcf)	**0.40**	1.11	**0.62**	0.88
Natural gas – after hedging ($/mcf)	**4.43**	5.25	**4.66**	5.77
Oil and natural gas liquids ($/bbl)	**84.06**	65.58	**80.18**	67.21
Total Hedging ($/mcfe)	**0.35**	0.94	**0.55**	0.74
Total Hedging ($/boe)	**2.10**	5.63	**3.30**	4.45

Peyto's natural gas price, before hedging gains, averaged $4.03/mcf during the second quarter of 2011, a decrease of 3 percent from $4.14/mcf reported for the equivalent period in 2010. Oil and natural gas liquids prices averaged $84.06/bbl, an increase of 28 percent from $65.58/bbl a year earlier. Hedging activity increased Peyto's achieved price/mcfe by 7% from $5.15 to 5.50.

Revenue

	Three Months ended June 30		Six Months ended June 30	
($000)	**2011**	2010	**2011**	2010
Natural gas	**67,452**	42,325	**128,223**	95,755
Oil and natural gas liquids	**29,155**	20,677	**54,842**	41,336
Hedging gain	**6,586**	11,368	**19,705**	17,253
Total revenue	**103,193**	74,370	**202,770**	154,344

For the three months ended June 30, 2011, revenue increased 39 percent to $103.2 million from $74.4 million for the same period in 2010. 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 June 30			Six Months ended June 30		
	2011	2010	**$million**	2011	2010	**$million**
Total Revenue, June 30, 2010			**74.4**			**154.3**
Revenue change due to:						
Natural gas						
Volume (mmcf)	16,725	10,230	**34.1**	31,729	19,585	**70.1**
Price ($/mcf)	$4.43	$5.25	**(13.7)**	$4.66	$5.77	**(35.2)**
Oil & NGL						
Volume (mbbl)	347	315	**2.0**	684	615	**4.7**
Price ($/bbl)	$84.06	$65.58	**6.4**	$80.18	$67.21	**8.9**
Total Revenue, June 30, 2011			**103.2**			**202.8**

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 June 30 **2011**	2010	Six Months ended June 30 **2011**	2010
Royalties	**12,007**	9,721	**21,929**	18,894
% of sales before hedging	**12.4**	15.4	**12.0**	13.8
% of sales after hedging	**11.6**	13.1	**10.8**	12.2
$/mcfe	**0.64**	0.81	**0.61**	0.81
$/boe	**3.84**	4.81	**3.67**	4.87

For the second quarter of 2011, royalties averaged $0.64/mcfe or approximately 11.6% of Peyto's total petroleum and natural gas sales.

Substantially all of Peyto's production is in the 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 Peyto 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 terminated on March 31, 2011. Under this program credits were earned at a rate of $200 per meter of newly drilled well depth and could be applied with certain limitations to the earning company's corporate royalty bill. For the three months ending June 30, 2011 $2.6 million in Alberta drilling credits were 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 $2.0 billion in capital projects, found and developed 1.2 TCFe of gas reserves, and paid over $554 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 June 30 **2011**	2010	Six Months ended June 30 **2011**	2010
Operating costs ($000)				
Field expenses	**8,067**	7,377	**17,002**	14,510
Processing and gathering recoveries	**(2,122)**	(2,765)	**(4,486)**	(5,338)
Total operating costs	**5,945**	4,612	**12,516**	9,172
$/mcfe	**0.32**	0.38	**0.35**	0.39
$/boe	**1.90**	2.28	**2.10**	2.36
Transportation	**2,371**	1,578	**4,535**	3,013
$/mcfe	**0.13**	0.13	**0.13**	0.13
$/boe	**0.76**	0.78	**0.76**	0.78

Operating costs increased to $5.9 million in the second quarter of 2011 from $4.6 million for the equivalent period in 2010 due to increased production volumes. On a unit-of-production basis, operating costs averaged $0.32/mcfe in the second quarter of 2011 compared to $0.38/mcfe for the equivalent period in 2010. Transportation expense was unchanged on a per mcfe basis.

General and Administrative Expenses

	Three Months ended June 30		Six Months ended June 30	
	2011	2010	**2011**	2010
G&A expenses ($000)	**2,635**	2,020	**5,699**	4,737
Overhead recoveries	**(1,287)**	(1,096)	**(2,745)**	(2,267)
Net G&A expenses	**1,348**	924	**2,954**	2,470
$/mcfe	**0.07**	0.08	**0.08**	0.11
$/boe	**0.41**	0.46	**0.48**	0.64

For the second quarter, general and administrative expenses before overhead recoveries were up 30% over the same quarter of 2010 due increased staffing, consulting and systems costs. Capital overhead recoveries increased 17 percent for the second quarter from $1.1 million to $1.3 million as a result of the increased capital program in 2011. General and administrative expenses averaged $0.07/mcfe in the second quarter of 2011 compared to $0.08/mcfe for the equivalent period in 2010.

Interest Expense

	Three Months ended June 30		Six Months ended June 30	
	2011	2010	**2011**	2010
Interest expense ($000)	**4,512**	4,969	**9,130**	9,381
$/mcfe	**0.24**	0.41	**0.25**	0.40
$/boe	**1.44**	2.46	**1.53**	2.42
Average interest rate	**4.1%**	4.9%	**4.4%**	4.4%

Second quarter 2011 interest expense was $4.5 million or $0.24/mcfe compared to $5.0 million or $0.41/mcfe for the second quarter 2010 due to a reduction in interest rates.

Netbacks

	Three Months ended June 30		Six Months ended June 30	
($/mcfe)	**2011**	2010	**2011**	2010
Gross Sale Price	**5.15**	5.20	**5.11**	6.63
Hedging gain	**0.35**	0.94	**0.55**	0.74
Net Sale Price	**5.50**	6.14	**5.66**	6.63
Less: Royalties	**0.64**	0.81	**0.61**	0.81
Operating costs	**0.32**	0.38	**0.35**	0.39
Transportation	**0.13**	0.13	**0.13**	0.13
Field netback	**4.41**	4.82	**4.57**	5.30
General and administrative	**0.07**	0.08	**0.08**	0.11
Interest on long-term debt	**0.24**	0.41	**0.25**	0.40
Cash netback ($/mcfe)	**4.10**	4.33	**4.24**	4.79
Cash netback ($/boe)	**24.60**	25.98	**25.44**	28.74

Netbacks are a non-IFRS 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 Amortization

Under IFRS, Peyto uses proved plus probable reserves as its depletion base to calculate depletion expense. The 2011 second quarter provision for depletion, depreciation and amortization totaled $30.9 million as compared to $19.2 million in 2010 due to higher levels of production and a larger asset base. On a unit-of-production basis, depletion and depreciation costs averaged $1.64/mcfe as compared to $1.60/mcfe in 2010.

Income Taxes

The current provision for deferred income tax expense is $10.9 million (2010 recovery – $0.3 million). On December 31, 2010, the Company converted from a publicly traded income trust to a publicly traded corporation pursuant to the 2010 Arrangement. As a result, for the period ended June 30, 2011, the Company's deferred income tax expense was calculated on the basis of it being a corporation. For the period ended June 30, 2010, the Company's deferred 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. Under the previous Trust structure, the distributions made by the Trust were deductible in determining the Trust's taxable income and accordingly reduced the overall provision for income taxes for the three months ended June 30, 2010. Peyto made no cash payments or tax installments for the three months ended June 30, 2011 or for the comparative period in 2010. Resource pools are generated from the capital program, which are available to offset current and deferred income tax liabilities.

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 the second quarter of 2011, a realized hedging gain of $6.6 million was recorded as compared to $11.4 million for the equivalent period in 2010. A summary of contracts outstanding in respect of the hedging activities are as follows:

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
April 1, 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, 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 October 31, 2011	Fixed Price	5,000 GJ	$3.80/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
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
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.055/GJ
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$3.80/GJ
May 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.00/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.17/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.10/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.10/GJ
July 1, 2011 to October 31, 2011	Fixed Price	5,000 GJ	$4.03/GJ
November 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.50/GJ
November 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ

As at June 30, 2011, Peyto had committed to the future sale of 38,770,000 gigajoules (GJ) of natural gas at an average price of $4.31 per GJ or $5.05 per mcf based on Peyto's historical heat content premium. Had these contracts been closed on June 30, 2011, Peyto would have realized a gain in the amount of $18.6 million.

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 June 30, 2011, 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 $1.1 million per quarter. Average debt outstanding for the second quarter of 2011 was $440.2 million.

LIQUIDITY AND CAPITAL RESOURCES

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

	Three Months ended June 30		Six Months ended June 30	
($000)	**2011**	2010	**2011**	2010
Cash flows from operating activities	**81,831**	56,073	**124,718**	108,746
Change in non-cash working capital	**(7,169)**	(6,598)	**20,416**	(1,229)
Change in provision for performance based compensation	**2,348**	3,090	**6,572**	3,897
Funds from operations	**77,010**	52,565	**151,706**	111,414
Funds from operations per share	**0.58**	0.44	**1.14**	0.95

For the second quarter ended June 30, 2011, funds from operations totaled $77.0 million or $0.58 per share, as compared to $52.6 million, or $0.44 per share during the same quarter in 2010. 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, 2012. 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 June 30, 2011 was 4.1% (2010 – 4.9%). 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 June 30, 2011, $455 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At June 30, 2011, the working capital deficit was $9.8 million (including a non-cash current asset for an unrealized mark to market future hedging gain of $18.4 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 $350 to $375 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-IFRS 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 IFRS measure:

($000)	**As at June 30, 2011**	As at December 31, 2010	As at June 30, 2010
Long-term debt	**455,000**	355,000	430,000
Current liabilities	**98,737**	134,757	58,412
Current assets	**(88,904)**	(104,720)	(93,396)
Financial derivative instruments	**18,448**	25,247	29,084
Gain on disposition of capital assets	**818**	-	-
Provision for future performance based compensation	**(10,091)**	(5,340)	(6,246)
Net debt	**474,008**	404,944	417,854

Capital

Authorized: Unlimited number of voting common shares

Issued and Outstanding Trust Units (no par value) ($000)	**Number of Units**	**Amount**
Balance, January 1, 2010	**114,920,194**	**501,219**
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)	-	(7,680)
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)	(755,831)
Balance, December 31, 2010	**-**	**-**

Issued and Outstanding Common shares (no par value) ($000)	**Number of Shares**	**Amount**
Issue common shares for trust units pursuant to the Arrangement	131,875,382	755,831
Balance, December 31, 2010	**131,875,382**	**755,831**
Common shares issued by private placement	906,196	17,150
Common shares issuance costs (net of tax)	-	(75)
Common shares issued pursuant to DRIP	113,527	1,973
Common shares issued pursuant to OTUPP	166,196	2,889
Balance, June 30, 2011	**133,061,301**	**777,768**

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.

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 share). These shares were issued on January 6, 2011.

On January 14, 2011, 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.

On March 25, 2011, Peyto completed a private placement of 250,615 common shares to employees and consultants for net proceeds of $4.6 million ($18.86 per share). Subsequent to the issuance of these shares, 133,061,301 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, dividends, general and administrative expenses and interest expense, 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 $1.3 million was recorded for the six months ended June 30, 2011.

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.

Based on the weighted average trading price of the common shares for the period ended June 30, 2011, compensation costs related to 3.6 million non-vested rights (3% of the total number of common shares outstanding), with an average grant price of $15.77, are $2.0 million for the second quarter of 2011. The Company records a non-cash provision for future compensation expense over the life of the rights calculated using a Black-Scholes valuation model (refer to Note 12 of the Condensed Interim Financial Statements for the more details). The cumulative provision totals $12.0 million.

Capital Expenditures

Net capital expenditures for the second quarter of 2011 totaled $69.0 million. Exploration and development related activity net of drilling royalty credits represented $47.1 million (68% of total), while expenditures on facilities, gathering systems and equipment totaled $20.6 million (30% of total) and land, seismic and acquisitions/dispositions totaled $1.3 million (2% of total). The following table summarizes capital expenditures for the period:

	Three Months ended June 30		Six Months ended June 30	
($000)	**2011**	2010	**2011**	2010
Land	**678**	-	**1,932**	244
Seismic	**663**	82	**751**	108
Drilling – Exploratory & Development	**47,111**	27,047	**130,568**	66,426
Production Equipment, Facilities & Pipelines	**20,557**	10,258	**35,196**	20,259
Acquisitions	**8**	203	**5,054**	203
Dispositions	**-**	-	**(698)**	-
Total Capital Expenditures	**69,017**	37,590	**172,803**	87,240

Dividends

	Three Months ended June 30		Six Months ended June 30	
	2011	2010	**2011**	2010
Funds from operations ($000)	**77,010**	52,565	**151,706**	111,414
Total dividends ($000)	**23,951**	43,622	**47,872**	85,093
Total dividends per share ($)	**0.18**	0.36	**0.36**	0.72
Payout ratio (%)	**31**	83	**32**	76

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.

Contractual Obligations

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

($000)	**June 30, 2011**
2011	529
2012	1,058
2013	1,058
2014	1,058
	3,703

RELATED PARTY TRANSACTIONS

An officer and director of Peyto 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.

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 IFRS. 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 June 30, 2011 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
All costs of exploring for and developing petroleum and natural gas reserves, together with the costs of production equipment, are capitalized and then 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 for gas plants and other facilities are capitalized and depreciated on a declining balance basis.

Impairment of Long-Lived Assets
Impairment is indicated if the carrying value of the long-lived asset or oil and gas cash generating unit exceeds its recoverable amount under IFRS. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the long-lived asset is charged to earnings. The determination of the recoverable amount for impairment purposes under IFRS involves the use of numerous assumptions and judgments including future net cash flows from oil and gas reserves, future third-party pricing, inflation factors, discount rates and other uncertainties. Future revisions to these assumptions impact the recoverable amount.

Future Market Performance Based Compensation
The provision for future market based compensation is estimated based on current market conditions, dividend 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, dividends, general and administrative expenses and interest expense. 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 IFRS 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 IFRS will have on the financial statements in the period of initial application.

CHANGES IN ACCOUNTING POLICIES

Presentation of Financial Statements
As of January 1, 2012, the Company will be required to adopt IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and also require the Company to group items within OCI based on whether the items may be subsequently reclassified to profit or loss. The adoption of the amendments to this standard is not expected to have a material impact on the Company's financial position or results.

Financial Instruments
As of January 1, 2013, the Company will be required to adopt IFRS 9 "Financial Instruments" which covers the classification and measurement of financial assets as part of its project to replace IAS 39 "Financial Instruments:

Recognition and Measurement." This standard replaces the current models for financial assets and liabilities with a single model. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to its own credit risk out of profit or loss and recognize the change in other comprehensive income. The implementation of the issued standard is not expected to have a material impact on the Company's financial position or results.

Consolidated Financial Statements
As of January 1, 2013, the Company will be required to adopt IFRS 10, "Consolidated Financial Statements," which provides a single control model to be applied in the assessment of control for all entities in which the Company has an investment including special purpose entities currently in the scope of Standing Interpretations Committee ("SIC") 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to the variability of returns from the investment and there is a linkage between the ability to direct activities and the variability of returns. The Company does not expect IFRS 10 to have a material impact on its financial position or results.

Joint Arrangements
As of January 1, 2013, the Company will be required to adopt IFRS 11, "Joint Arrangements," which specifies that joint arrangements are classified as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation, while parties to a joint venture have rights to the net assets of the venture. Any arrangement which is not structured through a separate entity or is structured through a separate entity but such separation is ineffective such that the parties to the arrangement have rights to the assets and obligations for the liabilities will be classified as a joint operation. Joint operations shall be accounted for in a manner consistent with jointly controlled assets and operations whereby the Company's contractual share of the arrangement's assets, liabilities, revenues and expenses are included in the consolidated financial statements. Any arrangement structured through a separate vehicle that does effectively result in separation between the Company and the arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the existing IFRS standard, the Company has the option to account for any interests it has in joint ventures using proportionate consolidation or equity accounting. The Company does not expect IFRS 11 to have a material impact on its financial position or results.

Disclosure of Interests in Other Entities
As of January 1, 2013, the Company will be required to adopt IFRS 12, "Disclosure of Interests in Other Entities," which contains new disclosure requirements for interests the Company has in subsidiaries, joint arrangements, associates and unconsolidated structured entities. Required disclosures aim to provide readers of the financial statements with information to evaluate the nature of and risks associated with the Company's interests in other entities and the effects of those interests on the Company's financial statements. The Company intends to adopt IFRS 12 in its financial statements for the annual period beginning on January 1, 2013. The Company does not expect IFRS 12 to have a material impact on its financial position or results.

Investments in Associates and Joint Ventures
As of January 1, 2013, the Company will be required to adopt amendments to IAS 28, "Investments in Associates and Joint Ventures," which provide additional guidance applicable to accounting for interests in joint ventures or associates when a portion of an interest is classified as held for sale or when the Company ceases to have joint control or significant influence over an associate or joint venture. When joint control or significant influence over an associate or joint venture ceases, the Company will no longer be required to re-measure the investment at that date. When a portion of an interest in a joint venture or associate is classified as held for sale, the portion not classified as held for sale shall be accounted for using the equity method of accounting until the sale is completed at which time the interest is reassessed for prospective accounting treatment. The Company does not expect the amendments to IAS 28 to have a material impact on the financial position or results.

Fair Value Measurement
As of January 1, 2013, the Company will be required to adopt IFRS 13, "Fair Value Measurement," which replaces fair value measurement guidance contained in individual IFRSs, providing a single source of fair value measurement guidance. The standard provides a framework for measuring fair value and establishes new disclosure requirements to enable readers to assess the methods and inputs used to develop fair value measurements and for recurring valuations that are subject to measurement uncertainty, the effect of those measurements on the financial statements. The Company intends to adopt IFRS 13 prospectively in its financial statements for the annual period beginning on January 1, 2013. The extent of the impact of adoption of IFRS 13 has not yet been determined.

Employee Benefits
As of January 1, 2013, the Company will be required to adopt IAS 19, "Employee Benefits" which eliminates the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for

changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. The Company does not expect the amendments to IAS 19 to have a material impact on the financial position or results.

International Financial Reporting Standards (“IFRS”)
Peyto has completed its adoption of IFRS for the year beginning on January 1, 2011. As a result, the Company's financial results for the second quarter ended June 30, 2011 and comparative periods are reported under IFRS while selected historical data continues to be reported under previous Canadian GAAP. (Refer to Note 17 of the Condensed Interim Financial Statements for the Company’s assessment of impacts of the transition 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

	2011		2010		
	Q2	Q1	Q4	Q3	Q2
Operations					
Production					
Natural gas (mcf/d)	183,790	166,710	148,551	122,717	112,422
Oil & NGLs (bbl/d)	3,811	3,746	3,439	3,322	3,465
Barrels of oil equivalent (boe/d @ 6:1)	34,443	31,531	28,197	23,775	22,202
Thousand cubic feet equivalent (mcfe/d @ 6:1)	206,657	189,187	169,184	142,651	133,211
Average product prices					
Natural gas ($/mcf)	4.43	4.92	4.93	5.16	5.25
Oil & natural gas liquids ($/bbl)	84.06	76.19	67.06	59.66	65.58
$/MCFE					
Average sale price ($/mcfe)	5.50	5.85	5.70	5.83	6.14
Average royalties paid ($/mcfe)	0.64	0.58	0.50	0.52	0.81
Average operating expenses ($/mcfe)	0.32	0.39	0.31	0.34	0.38
Average transportation costs ($/mcfe)	0.13	0.13	0.14	0.14	0.13
Field netback ($/mcfe)	4.41	4.75	4.75	4.83	4.82
General & administrative expense ($/mcfe)	0.07	0.09	(0.05)	0.15	0.08
Interest expense ($/mcfe)	0.24	0.27	0.36	0.39	0.41
Cash netback ($/mcfe)	4.10	4.39	4.26	4.32	4.32
Financial ($000 except per share)					
Revenue	103,193	99,577	88,633	76,450	74,370
Royalties	12,007	9,922	7,712	6,800	9,721
Funds from operations	77,010	74,696	99,064	56,341	52,565
Funds from operations per share	0.58	0.56	0.79	0.46	0.44
Total dividends	23,951	23,921	46,299	43,875	43,622
Total dividends per share	0.18	0.18	0.36	0.36	0.36
Payout ratio	31%	32%	65%	78%	83%
Earnings	32,718	31,688	95,419	33,983	30,384
Earnings per diluted share	0.25	0.24	0.76	0.28	0.25
Capital expenditures	69,017	103,786	113,403	63,721	37,590
Weighted average shares outstanding	133,061,301	132,737,066	125,726,450	121,765,712	119,419,799

Peyto Exploration & Development Corp.

Condensed Balance Sheet *(unaudited)*

(Amount in $ thousands)

	June 30 2011	December 31 2010	January 1 2010
Assets			
Current assets			
Cash	12,349	7,894	-
Accounts receivable *(Note 3)*	52,481	55,876	58,305
Due from private placement *(Note 7)*	-	12,423	2,728
Financial derivative instruments *(Note 12)*	18,448	25,247	8,683
Prepaid expenses	5,626	3,280	3,786
	88,904	**104,720**	**73,502**
Financial derivative instruments *(Note 12)*	188	2,664	1,254
Prepaid capital	4,661	-	955
Property, plant and equipment, net *(Note 4)*	1,482,865	1,367,869	1,178,402
	1,487,714	**1,370,533**	**1,180,611**
	1,576,618	**1,475,253**	**1,254,113**
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	80,662	113,592	55,890
Dividends payable *(Note 7)*	7,984	15,825	13,790
Provision for future performance based compensation *(Note 11)*	10,091	5,340	3,395
	98,737	**134,757**	**73,075**
Long-term debt *(Note 5)*	455,000	355,000	435,000
Provision for future performance based compensation *(Note 11)*	3,189	1,369	1,016
Decommissioning provision *(Note 6)*	27,208	24,734	17,479
Deferred income taxes	133,279	114,610	191,907
	618,676	**495,713**	**645,402**
Shareholders' or Unitholders' equity			
Shareholders' capital *(Note 7)*	777,768	755,831	-
Unitholders' capital *(Note 7)*	-	-	501,219
Shares or Units to be issued *(Note 7)*	-	17,285	2,728
Retained earnings	67,308	50,774	25,627
Accumulated other comprehensive income *(Note 7)*	14,129	20,893	6,062
	859,205	**844,783**	**535,636**
	1,576,618	**1,475,253**	**1,254,113**

Approved by the Board of Directors

(signed) *"Michael MacBean"*
Director

(signed) *"Darren Gee"*
Director

Peyto Exploration & Development Corp.

Condensed Income Statement *(unaudited)*

(Amount in $ thousands)

	Three months ended June 30		Six months ended June 30	
	2011	**2010**	**2011**	**2010**
Revenue				
Oil and gas sales	96,607	63,002	183,065	137,091
Realized gain on hedges *(Note 12)*	6,586	11,368	19,705	17,253
Royalties	(12,007)	(9,721)	(21,929)	(18,894)
Petroleum and natural gas sales, net	**91,186**	**64,649**	**180,841**	**135,450**
Expenses				
Operating *(Note 8)*	5,945	4,612	12,516	9,172
Transportation	2,371	1,578	4,535	3,013
General and administrative *(Note 9)*	1,348	924	2,954	2,470
Future performance based compensation *(Note 11)*	2,348	3,091	6,572	3,897
Interest *(Note 10)*	4,512	4,969	9,130	9,381
Accretion of decommissioning liability *(Note 10)*	234	168	465	346
Depletion and depreciation *(Note 4)*	30,850	19,228	59,876	36,974
Gains on divestitures	-	-	(818)	-
	47,608	**34,570**	**95,230**	**65,253**
Earnings before taxes	**43,578**	**30,079**	**85,611**	**70,197**
Taxes				
Deferred income tax expense (recovery)	10,860	(305)	21,205	(815)
Earnings for the period	**32,718**	**30,384**	**64,406**	**71,012**
Earnings per share or unit *(Note 7)*				
Basic and diluted	**$ 0.25**	**$ 0.25**	**$ 0.49**	**$ 0.61**
Weighted average number of common shares outstanding *(Note 7)*				
Basic and diluted	**133,061,301**	**119,419,799**	**132,900,079**	**117,298,518**

Peyto Exploration & Development Corp.

Condensed Statement of Comprehensive Income *(unaudited)*

(Amount in $ thousands)

	Three months ended June 30		Six months ended June 30	
	2011	**2010**	**2011**	**2010**
Earnings for the period	**32,718**	**30,384**	**64,406**	**71,012**
Other comprehensive income				
Change in unrealized gain (loss) on cash flow hedges	6,591	3,653	12,941	31,274
(net of deferred tax;				
2011 - $0.1 million recovery and $2.5 million recovery				
(2010 - $4.9 million recovery and $8.8 million expense))				
Realized (gain) loss on cash flow hedges	(6,586)	(11,368)	(19,705)	(17,253)
Comprehensive Income	**32,723**	**22,669**	**57,642**	**85,033**

Peyto Exploration & Development Corp.

Condensed Statement of Changes in Equity *(unaudited)*

(Amount in $ thousands)

	Six months ended June 30	
	2011	**2010**
Shareholders' / Unitholders' capital, Beginning of Year	**755,831**	501,219
Trust units issued	**-**	74,863
Common shares / trust units issued by private placement	17,150	2,728
Common shares / trust units issuance costs (net of tax)	(75)	(2,421)
Common shares / trust units issued pursuant to DRIP	1,973	3,174
Common shares / trust units issued pursuant to OTUPP	2,889	6,987
Shareholders' / Unitholders' capital, End of Period	**777,768**	586,550

Common shares / trust units to be issued, Beginning of Year	**17,285**	2,728
Common shares / trust units issued	(17,285)	(2,728)
Trust units to be issued	-	994
Common shares / trust units to be issued, End of Period	**-**	994

Retained earnings, Beginning of Year	**50,774**	25,627
Earnings for the period	64,406	71,012
Dividends *(Note 7)*	(47,872)	(85,093)
Retained earnings, End of Period	**67,308**	11,546

Accumulated other comprehensive income, Beginning of Year	**20,893**	6,062
Other comprehensive income (loss)	(6,764)	14,021
Accumulated other comprehensive income, End of Period	**14,129**	20,083

Total Shareholders' Equity	**859,205**	619,173

Peyto Exploration & Development Corp.

Consolidated Statement of Cash Flows *(unaudited)*

(Amount in $ thousands)

	Three months ended June 30		Six months ended June 30	
	2011	**2010**	**2011**	**2010**
Cash provided by (used in)				
Operating Activities				
Earnings	**32,718**	30,384	**64,406**	71,012
Items not requiring cash:				
Deferred income tax	**10,860**	(305)	**21,205**	(815)
Depletion and depreciation	**30,850**	19,228	**59,876**	36,974
Gain on disposition of assets	**-**	-	**(818)**	-
Accretion of decommissioning liability	**234**	168	**465**	346
Change in non-cash working capital related to operating activities *(Note 15)*	**7,169**	6,598	**(20,416)**	1,229
	81,831	56,073	**124,718**	108,746
Financing Activities				
Issuance of common shares	**-**	78,950	**4,628**	80,605
Issuance costs	**(13)**	(2,421)	**-**	(2,421)
Dividends paid	**(23,951)**	(41,977)	**(47,872)**	(81,227)
Increase (decrease) in bank debt	**30,000**	(20,000)	**100,000**	(5,000)
Change in non-cash working capital related to financing activities *(Note 15)*	**-**	766	**4,581**	2,823
	6,036	15,318	**61,337**	(5,220)
Investing Activities				
Additions to property, plant and equipment	**(73,678)**	(37,602)	**(176,707)**	(86,365)
Change in non-cash working capital related to investing activities *(Note 15)*	**(12,580)**	(24,513)	**(4,893)**	(7,885)
	(86,258)	(62,115)	**(181,600)**	(94,250)
Net increase in cash	**1,609**	9,276	**4,455**	9,276
Cash, beginning of year	**10,740**	-	**7,894**	-
Cash, end of period	**12,349**	9,276	**12,349**	9,276

The following amounts are included in Cash Flows From Operating Activities:

Cash interest paid	4,512	4,969	9,130	9,381
Cash taxes paid	-	-	-	-

Peyto Exploration & Development Corp.

Notes to Condensed Financial Statements *(unaudited)*

As at June 30, 2011 and 2010

(Amount in $ thousands, except as otherwise noted)

1. Nature of operations

Peyto Exploration & Development Corp. ("Peyto" or the "Company") is a Calgary based oil and natural gas company. The Company conducts exploration, development and production activities in Canada. Peyto is incorporated and domiciled in the Province of Alberta, Canada. The address of its registered office is 1500, 250 – 2nd Street SW, Calgary, Alberta, Canada, T2P 0C1.

On December 31, 2010, Peyto completed the conversion from an income trust to a corporation pursuant to an arrangement under the *Business Corporations Act* (Alberta); the ("2010 Arrangement"). As a result of this conversion, units of Peyto Energy Trust (the "Trust") were exchanged for common shares of Peyto on a one-for-one basis (see Note 7).

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.

There were no changes in Peyto's underlying operations associated with the 2010 Arrangement. The condensed 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, the condensed financial statements refer to common shares, shareholders and dividends although for the pre-conversion period such items were trust units, unitholders' and distributions, respectively.

Following the completion of the 2010 Arrangement, Peyto does not have any subsidiaries.

These condensed financial statements were approved and authorized for issuance by the Audit Committee of the Board of Directors of Peyto on August 9, 2011.

2. Basis of presentation

These unaudited condensed financial statements ("financial statements") for the three and six months ended June 30, 2011 have been prepared in accordance with International Accounting Standard ("IAS") 34 *Interim Financial Reporting*. These condensed interim financial statements do not include all of the information required for annual financial statements. Amounts relating to the three and six months ended June 30, 2010 and as at December 31, 2010 were previously presented in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These amounts have been restated as necessary to be compliant with our accounting policies under International Financial Reporting Standards ("IFRS"), which are included below. Reconciliations and descriptions relating to the transition from Canadian GAAP to IFRS are included in Note 17.

a) Summary of significant accounting policies

The precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the Company's basis of presentation as disclosed.

The following significant accounting policies have been adopted in the preparation and presentation of the financial report:

b) Significant accounting estimates and judgements

The timely preparation of the unaudited condensed financial statements in conformity with International Financial Reporting Standards ("IFRS") 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 unaudited condensed 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 condensed financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion and amortization, decommissioning costs and obligations and amounts used for 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 condensed 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.

c) Presentation currency

All amounts in these financial statements are expressed in Canadian dollars, as this is the functional and presentation currency of the Company.

d) Jointly controlled assets

A jointly controlled asset involves joint control and offers joint ownership by the Company and other partners of assets contributed to or acquired for the purpose of the jointly controlled assets, without the formation of a corporation, partnership or other entity.

The Company accounts for its share of the jointly controlled assets, any liabilities it has incurred, its share of any liabilities jointly incurred with its partners, income from the sale or use of its share of the joint venture's output, together with its share of the expenses incurred by the jointly controlled asset and any expenses it incurs in relation to its interest in the jointly controlled asset.

e) Exploration and evaluation assets

Pre-license costs

Costs incurred prior to obtaining the legal right to explore for hydrocarbon resources are expensed in the period in which they are incurred. The Company has no pre-license costs.

Exploration and evaluation costs

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as exploration and evaluation intangible assets until the drilling of the well is complete and the results have been evaluated. All such costs are subject to technical feasibility, commercial viability and management review as well as review for impairment at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. The Company has no exploration or evaluation costs.

f) Property, plant and equipment, net

Oil and gas properties and other property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning provision and borrowing costs for qualifying assets. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Costs include expenditures on the construction, installation or completion of infrastructure such well sites, pipelines and facilities including activities such as drilling, completion and tie-in costs, equipment and installation costs, associated geological and human resource costs, including unsuccessful development or delineation wells.

Oil and natural gas asset swaps

For exchanges or parts of exchanges that involve assets, the exchange is accounted for at fair value. Assets are then de-recognized at their current carrying value.

Depletion and Depreciation

Oil and natural gas properties are depleted on a unit-of-production basis over the proved plus probable reserves. All costs related to oil and natural gas properties (net of salvage value) and estimated costs of future development of proved plus probable undeveloped reserves are depleted and depreciated using the unit-of-production method based on estimated gross proved plus probable 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.

Other property, plant and equipment are depreciated using a declining balance method over remaining useful life.

g) Corporate Assets

Corporate assets not related to oil and natural gas exploration and development activities are recorded at historical costs and depreciated over their useful life. These assets are not significant or material in nature.

h) Impairment of non-financial assets

The Company assesses at each reporting date whether there is an indication that an asset may be impaired. If any indication exists, or when annual impairment testing for an asset is required, the Company estimates the asset's recoverable amount. An asset's recoverable amount is the higher of fair value less costs to sell or value-in-use and is determined for an individual asset, unless the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, in which case the recoverable amount is assessed as part of a cash generating unit ("CGU"). If the carrying amount of an asset or CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. In assessing value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In determining fair value less costs to sell, recent market transactions are taken into account, if available. If no such transactions can be identified, an appropriate valuation model is used. These calculations are corroborated by valuation multiples, quoted share prices for publicly traded subsidiaries or other available fair value indicators.

Impairment losses of continuing operations are recognized in the income statement.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the Company estimates the asset's or cash-generating unit's recoverable amount. A previously recognized impairment loss is reversed only if there has been a change in the assumptions used to determine the asset's recoverable amount since the last impairment loss was recognized. The reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount, nor exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years.

i) Leases

Leases or other arrangements entered into for the use of an asset are classified as either finance or operating leases. Finance leases transfer to the Company substantially all of the risks and benefits incidental to ownership of the leased asset. Assets under finance lease are amortized over the shorter of the estimated useful life of the assets and the lease term. All other leases are classified as operating leases and the payments are amortized on a straight-line basis over the lease term.

j) Financial instruments

Financial instruments within the scope of IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39") are initially recognized at fair value on the condensed balance sheet. The Company has classified each financial instrument into the following categories: "fair value through profit or loss"; "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	Fair value through profit or loss
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
Dividends Payable	Other Liabilities
Long Term Debt	Other Liabilities
Financial Derivative Instruments	Fair value through profit or loss

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 condensed income statement, 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.

Normal purchase or sale exemption

Contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements fall within the exemption from IAS 32 *Financial Instruments: Presentation* ("IAS 32") and IAS 39, which is known as the 'normal purchase or sale exemption'. The Company recognizes such contracts in its balance sheet only when one of the parties meets its obligation under the contract to deliver either cash or a non-financial asset.

k) Hedging

The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. 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 oil and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. 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.

l) Inventories

Inventories are stated at the lower of cost and net realizable value. Cost of producing oil and natural gas is accounted on a weighted average basis. This cost includes all costs incurred in the normal course of business in bringing each product to its present location and condition.

m) Provisions

General

Provisions are recognized when the Company has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Company expects some or all of a provision to be reimbursed, the reimbursement is recognized as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is presented in the income statement net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as a finance cost.

Decommissioning provision

Decommissioning provision is recognized when the Company has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. A corresponding amount equivalent to the provision is also recognized as part of the cost of the related property, plant and equipment. The amount recognized is the estimated cost of decommissioning, discounted to its present value using a risk-free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The accretion of the discount on the decommissioning provision is included as a finance cost.

n) Taxes

Current income tax

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted, at the reporting date, in Canada.

Current income tax relating to items recognized directly in equity is recognized in equity and not in the income statement. Management periodically evaluates positions taken in the tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions where appropriate.

Deferred tax

The Company follows the liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantively enacted tax rates expected to apply when the asset is realized or the liability settled. Deferred tax assets are only recognized to the extent it is probable that sufficient future taxable income will be available to allow the future income tax asset to be realized. Accumulated deferred 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, except for items recognized in shareholders' equity.

o) Revenue recognition

Revenue from the sale of oil, natural gas and natural gas liquids is recognized when the significant risks and rewards of ownership have been transferred, which is when title passes to the purchaser. This generally occurs when product is physically transferred into a pipe or other delivery system.

Gains and Losses on Disposition

For all dispositions, either through sale or exchange, gains and losses are calculated as the difference between the sale or exchange value in the transaction and the carrying value of the disposed assets disposed. Gains and losses on disposition are recognized in earnings in the same period as the transaction date.

p) Borrowing costs

Borrowing costs directly relating to the acquisition, construction or production of a qualifying capital project under construction are capitalized and added to the project cost during construction until such time the assets are substantially ready for their intended use, which is, when they are capable of commercial production. Where the funds used to finance a project form part of general borrowings, the amount capitalized is calculated using a weighted average of rates applicable to relevant general borrowings of the Company during the period. All other borrowing costs are recognized in the income statement in the period in which they are incurred.

q) Share-based payments

Liability-settled share-based payments to employees are measured at the fair value of the liability award at the grant date. A liability equal to fair value of the payments is accrued over the vesting period measured at fair value using the Black-Scholes option pricing model.

The fair value determined at the grant date of the liability-settled share-based payments is expensed on a graded basis over the vesting period, based on the Company's estimate of liability instruments that will eventually vest. At the end of each reporting period, the Company revises its estimate of the number of liability instruments expected to vest. The impact of the revision of the original estimates, if any, is recognized in the income statement such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to related liability on the balance sheet.

r) Earnings per share

Basic and diluted earnings per share is computed by dividing the net earnings available to common shareholders by the weighted average number of shares outstanding during the reporting period. The Company has no dilutive instrument outstanding which would cause a difference between the basic and diluted earnings per share.

s) Share capital

Common shares are classified within shareholders' equity. Incremental costs directly attributable to the issuance of shares are recognized as a deduction from shareholders' capital.

t) Standards issued but not yet effective

Presentation of Financial Statements

As of January 1, 2012, the Company will be required to adopt IAS 1, "Presentation of Items of OCI: Amendments to IAS 1 Presentation of Financial Statements." The amendments stipulate the presentation of net earnings and OCI and also require the Company to group items within OCI based on whether the items may be subsequently reclassified to profit or loss. The adoption of the amendments to this standard is not expected to have a material impact on the Company's financial position or results.

Financial Instruments

As of January 1, 2013, the Company will be required to adopt IFRS 9 "Financial Instruments" which covers the classification and measurement of financial assets as part of its project to replace IAS 39 "Financial Instruments: Recognition and Measurement." This standard replaces the current models for financial assets and liabilities with a single model. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to its own credit risk out of profit or loss and recognize the change in other comprehensive income. The implementation of the issued standard is not expected to have a material impact on the Company's financial position or results.

Consolidated Financial Statements

As of January 1, 2013, the Company will be required to adopt IFRS 10, "Consolidated Financial Statements," which provides a single control model to be applied in the assessment of control for all entities in which the Company has an investment, including special purpose entities currently in the scope of Standing Interpretations Committee ("SIC") 12. Under the new control model, the Company has control over an investment if the Company has the ability to direct the activities of the investment, is exposed to the variability of returns from the investment and there is a linkage between the ability to direct activities and the variability of returns. The Company does not expect IFRS 10 to have a material impact on its financial position or results.

Joint Arrangements

As of January 1, 2013, the Company will be required to adopt IFRS 11, "Joint Arrangements," which specifies that joint arrangements are classified as either joint operations or joint ventures. Parties to a joint operation retain the rights and obligations to individual assets and liabilities of the operation, while parties to a joint venture have rights to the net assets of the venture. Any arrangement which is not structured through a separate entity or is structured through a separate entity but such separation is ineffective such that the parties to the arrangement have rights to the assets and obligations for the liabilities will be classified as a joint operation. Joint operations shall be accounted for in a manner consistent with jointly controlled assets and operations whereby the Company's contractual share of the arrangement's assets, liabilities, revenues and expenses are included in the consolidated financial statements. Any arrangement structured through a separate vehicle that does effectively result in separation between the Company and the arrangement shall be classified as a joint venture and accounted for using the equity method of accounting. Under the existing IFRS standard, the Company has the option to account for any interests it has in joint ventures using proportionate consolidation or equity accounting. The Company does not expect IFRS 11 to have a material impact on its financial position or results.

Disclosure of Interests in Other Entities

As of January 1, 2013, the Company will be required to adopt IFRS 12, "Disclosure of Interests in Other Entities," which contains new disclosure requirements for interests the Company has in subsidiaries, joint arrangements, associates and unconsolidated structured entities. Required disclosures aim to provide readers of the financial statements with information to evaluate the nature of and risks associated with the Company's interests in other entities and the effects of those interests on the Company's financial statements. The Company intends to adopt IFRS 12 in its financial statements for the annual period beginning on January 1, 2013. The Company does not expect IFRS 12 to have a material impact on its financial position or results.

Investments in Associates and Joint Ventures
As of January 1, 2013, the Company will be required to adopt amendments to IAS 28, "Investments in Associates and Joint Ventures," which provide additional guidance applicable to accounting for interests in joint ventures or associates when a portion of an interest is classified as held for sale or when the Company ceases to have joint control or significant influence over an associate or joint venture. When joint control or significant influence over an associate or joint venture ceases, the Company will no longer be required to re-measure the investment at that date. When a portion of an interest in a joint venture or associate is classified as held for sale, the portion not classified as held for sale shall be accounted for using the equity method of accounting until the sale is completed at which time the interest is reassessed for prospective accounting treatment. The Company does not expect the amendments to IAS 28 to have a material impact on the financial position or results.

Fair Value Measurement
As of January 1, 2013, the Company will be required to adopt IFRS 13, "Fair Value Measurement," which replaces fair value measurement guidance contained in individual IFRSs, providing a single source of fair value measurement guidance. The standard provides a framework for measuring fair value and establishes new disclosure requirements to enable readers to assess the methods and inputs used to develop fair value measurements and for recurring valuations that are subject to measurement uncertainty, the effect of those measurements on the financial statements. The Company intends to adopt IFRS 13 prospectively in its financial statements for the annual period beginning on January 1, 2013. The extent of the impact of adoption of IFRS 13 has not yet been determined.

Employee Benefits
As of January 1, 2013, the Company will be required to adopt IAS 19, "Employee Benefits" which eliminates the corridor method that permits the deferral of actuarial gains and losses, to revise the presentation requirements for changes in defined benefit plan assets and liabilities and to enhance the required disclosures for defined benefit plans. The Company does not expect the amendments to IAS 19 to have a material impact on the financial position or results.

3. Accounts receivable

	June 30 2011	December 31 2010	January 1 2010
Accounts receivable – general	45,326	48,721	51,150
Accounts receivable – tax	7,155	7,155	7,155
	52,481	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.

4. Property, plant and equipment, net

	Petroleum properties	Processing assets and facilities	Corporate assets	Total
Cost				
At January 1, 2010	1,112,677	65,353	1,007	1,179,037
Additions	255,374	19,607	-	274,981
Dispositions	(1,094)	-	-	(1,094)
At December 31, 2010	1,366,957	84,960	1,007	1,452,924
Additions	152,025	23,483	-	175,508

Dispositions	(698)	-	-	(698)
At June 30, 2011	1,518,284	108,443	1,007	1,627,734
Accumulated Depreciation				
At January 1, 2010	-	-	(635)	(635)
Depletion and depreciation	(80,496)	(3,867)	(89)	(84,452)
Dispositions	32	-	-	32
At December 31, 2010	(80,464)	(3,867)	(724)	(85,055)
Depletion and depreciation	(57,510)	(2,330)	(36)	(59,876)
Dispositions	62	-	-	62
At June 30, 2011	(137,912)	(6,197)	(760)	(144,869)
Net book value at June 30, 2011	1,380,372	102,246	247	1,482,865

During the three and six month period ended June 30, the Company capitalized $1.0 million and $2.3 million (2010 - $0.9 and $1.7 million) of general and administrative and share based payments directly attributable to production and development activities.

The Company performs an impairment test calculation when indicators are present which negatively affect the value of the Company's individual assets or its total asset base. Assets which have indicators of impairment are then aggregated to its cash-generating units at which point the measurement of impairment is calculated.

The Company did not have any indicators of impairment in the current period.

5. Long-term debt

The Company has a syndicated $625 million extendible revolving credit facility with a stated term date of April 29, 2012. 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 cash flow ratio that range from prime to prime plus 1.25% to 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.

Total cash interest expense for the three months ended was $4.5 million (2010 - $5.0 million) and the average borrowing rate for the period was 4.1% (2010 – 4.9%). Total cash interest expense for the six months ended was $9.1 million (2010 - $9.4 million) and the average borrowing rate for the period was 4.4% (2010 – 4.4%).

6. Decommissioning provision

The Company makes provision for the future cost of decommissioning wells, pipelines and facilities on a discounted basis based on the commissioning of these assets.

The decommissioning provision represents the present value of the decommissioning costs related to the above infrastructure, which are expected to be incurred over the economic life of the assets. The provisions have been based on the Company's internal estimates on the cost of decommissioning, the discount rate, the inflation rate and the economic life of the infrastructure. Assumptions, based on the current economic environment, have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon the future market prices for the necessary decommissioning work required which will reflect market conditions at the relevant time. Furthermore, the timing of the decommissioning is likely to depend on when production activities ceases to be economically viable. This in turn will depend and be directly related to the current and future commodity prices, which are inherently uncertain.

The following table reconciles the change in decommissioning liabilities:

Balance, December 31, 2010 (1)	**24,734**
New or increased provisions	2,094
Accretion of discount	465
Change in discount rate	(85)
Balance, June 30, 2011 (2)	**27,208**
Current	-
Non-current	27,208

(1) Based on a total future undiscounted liability of $86.1 million to be incurred over the next 50 years at an inflation rate of 2% and a discount rate of 3.54%.
(2) Based on a total future undiscounted liability of $93.7 million to be incurred over the next 50 years at an inflation rate of 2% and a discount rate of 3.55%.

7. Shareholders' capital and Unitholders' capital

Authorized: Unlimited number of voting common shares

Issued and Outstanding

Common Shares and Units (no par value)	Number of Common Shares	Amount $
Balance, January 1, 2010	114,920,194	501,219
Trust units issued	13,880,500	218,704
Trust units issuance costs (net of tax)	-	(7,680)
Trust units issued by private placement	196,420	2,728
Trust units issued pursuant to DRIP	746,079	10,558
Trust units issued pursuant to OTUPP	2,132,189	30,302
Exchanged for common shares pursuant to the Arrangement *(Note 1)*	(131,875,382)	(755,831)
Balance, December 31, 2010	131,875,382	755,831
Common shares issued by private placement	906,196	17,150
Common share issuance costs (net of tax)	-	(75)
Common shares issued pursuant to DRIP	113,527	1,973
Common shares issued pursuant to OTUPP	166,196	2,889
Balance, June 30, 2011	133,061,301	777,768

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).

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 Distribution Reinvestment Plan ("DRIP") 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.

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.

On January 14, 2011, 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.

On March 25, 2011, Peyto completed a private placement of 250,615 common shares to employees and consultants for net proceeds of $4.6 million ($18.86 per share). Subsequent to the issuance of these shares, 133,061,301 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 for the three month and six month period ended of 133,061,301 and 132,900,079 (2010 - 119,419,799 and 117,298,518), respectively. There are no dilutive instruments outstanding.

Dividends
During the three and six months ended June 30, 2011, Peyto declared and paid dividends of $0.18 and $0.36 per common share, respectively or $0.06 per common share per month, totaling $24.0 million and $47.9 million (2010 - $0.36 and $0.72 per share, respectively or $0.12 per share per month, $43.6 million and $85.1 million), respectively.

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 an equity category comprised of the cumulative amounts of OCI.

Accumulated hedging gains

	2011
Balance, January 1, 2011	20,893
Hedging gains (losses)	(6,764)
Balance, June 30, 2011	14,129

Gains and losses from cash flow hedges are accumulated until settled. These outstanding hedging contracts are recognized in earnings on settlement with gains and losses being recognized as a component of net revenue. Further information on these contracts is set out in Note 13.

8. Operating expenses

The Company’s operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering recoveries related to jointly controlled assets and third party natural gas reduces operating expenses.

	Three months ended June 30		**Six months ended June 30**	
	2011	**2010**	**2011**	**2010**
Field expenses	8,067	7,377	17,002	14,510
Processing and gathering recoveries	(2,122)	(2,765)	(4,486)	(5,338)
Total operating expenses	5,945	4,612	12,516	9,172

9. General and administrative expenses

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

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
General and administrative expenses	2,635	2,020	5,699	4,737
Overhead recoveries	(1,287)	(1,096)	(2,745)	(2,267)
Net general and administrative expenses	1,348	924	2,954	2,470

10. Finance costs

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Cash interest expense	4,512	4,969	9,130	9,381
Accretion of discount on provisions	234	168	465	346
	4,746	5,137	9,595	9,727

11. Future Performance based compensation

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

Reserve Based Component
The reserves value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity, distributions, general and administrative costs and interest, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%.

Market Based Component
Under the market based component, rights with a three year vesting period are allocated to employees. 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 common share for that period.

The fair values were calculated using a Black-Scholes valuation model. The principal inputs to the option valuation model were:

	June 30 2011	December 31 2010
Share price	$21.50	$18.49
Exercise price	$9.57 - $18.84	$6.62 – $11.66
Expected volatility	22% - 38%	0% - 28%
Option life	0.5 – 2.75 years	1 - 2 years
Dividend yield	0%	0%
Risk-free interest rate	1.58%	1.66%

12. Financial instruments

Financial Instrument Classification and Measurement
Financial instruments of the Company carried on the 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 June 30, 2011.

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 June 30, 2011, the carrying value of cash and financial derivative instruments are carried at fair value. Accounts receivable, due from private placement, current liabilities 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 June 30, 2011 is as follows:

Description	Notional (1)	Term	Effective Rate	Fair Value Level	June 30 2011	December 31 2010
Natural gas financial swaps - AECO	38.77GJ (2)	2011- 2013	$4.31/GJ	Level 1	18,636	27,911

(1) Notional values as at June 30, 2011 (2) Millions of gigajoules

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
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, 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 October 31, 2011	Fixed Price	5,000 GJ	$3.80/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 March 31, 2012	Fixed Price	5,000 GJ	$4.055/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
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
April 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$3.80/GJ
May 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.00/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.17/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.10/GJ
June 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.10/GJ
July 1, 2011 to October 31, 2011	Fixed Price	5,000 GJ	$4.03/GJ
November 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.50/GJ
November 1, 2011 to March 31, 2013	Fixed Price	5,000 GJ	$4.00/GJ

As at June 30, 2011, the Company had committed to the future sale of 38,770,000 gigajoules (GJ) of natural gas at an average price of $4.31 per GJ or $5.05 per mcf based on the historical heating value of Peyto's natural gas. Had these contracts been closed on June 30, 2011, the Company would have realized a gain in the amount of $18.6 million. If the AECO gas price on June 30, 2011 were to increase by $1/GJ, the unrealized gain would decrease by approximately $38.8 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.

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 three month and six month period ended June 30, 2011 would decrease by $1.1 million and $2.1 million, respectively. 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 three months ended June 30, 2011, approximately 82% was received from seven companies (16%, 12%, 12%, 11%, 11%, 10% and 10%) (June 30, 2010 – 87%, five companies (25%, 19%, 16%, 14% and 13%)). Of the Company's revenue for the six months ended June 30, 2011, approximately 76% was received from five companies (21%, 15%, 14%, 13% and 13%) (June 30, 2010 – 97%, six companies (25%, 19%, 16%, 13%, 13% and 11%)). Of the Company's accounts receivable for the period ended June 30, 2011, approximately 13% was receivable from a single company (Year ended December 31, 2010 – 31%, three companies (11%, 10% and 10%)). 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 June 30, 2011, 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 June 30, 2011:

	< 1 Year	1-2 Years	2-5 Years	Thereafter
Accounts payable and accrued liabilities	80,662			
Dividends payable	7,984			
Provision for future market and reserves based bonus	10,091	3,189		
Long-term debt[1]		455,000		

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

13. 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, adjust its capital spending or change dividends paid to manage its current and projected debt levels. The Company monitors capital based on the following non-IFRS 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.

	June 30 2011	December 31 2010
Shareholders' equity	859,205	844,783
Long-term debt	455,000	355,000
Working capital deficit	9,833	30,037
	1,324,038	1,229,820

14. Related party transactions

An officer and director of Peyto 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.

15. Supplemental cash flow information

Changes in non-cash working capital balances

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
(Increase)/decrease of assets:				
Accounts receivable	41	15,509	3,395	8,904
Due from private placement	-	-	12,423	2,728
Prepaid expenses	(2,028)	(2,572)	(2,346)	(1,848)
Increase/(decrease) of liabilities:				
Accounts payable and accrued liabilities	(5,770)	(33,941)	(32,930)	(17,609)
Dividends payable	-	765	(7,841)	95
Provision for future performance based compensation	2,346	3,090	6,571	3,897

	(5,411)	(17,149)	(20,728)	(3,833)
Attributable to operating activities	7,169	6,598	(20,416)	1,229
Attributable to financing activities	-	766	4,581	2,823
Attributable to investing activities	(12,580)	(24,513)	(4,893)	(7,885)
	(5,411)	(17,149)	(20,728)	(3,833)

16. Commitments and contingencies

Following is a summary of the Company's commitment related to an operating lease as at June 30, 2011.

	2011	2012	2013	2014	2015	Thereafter
Operating lease	529	1,058	1,058	1,058	-	-
Total	529	1,058	1,058	1,058	-	-

The Company has no other contractual obligations or commitments as at June 30, 2011.

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.

17. Transition to IFRS

For all periods up to and including the year ended December 31, 2010, the Company prepared its financial statements in accordance with Canadian GAAP. The Company has prepared financial statements which comply with IFRS's applicable for periods beginning on or after the transition date of January 1, 2010 and the significant accounting policies meeting those requirements are described in Note 2.

The effect of the Company's transition to IFRS is summarized in this note as follows:

(i) Transition elections
(ii) Reconciliation of the Balance Sheets, Income Statements and Comprehensive Income as previously reported under Canadian GAAP to IFRS
(iii) IFRS adjustments

(i) Transition elections

IFRS 1 allows first-time adopters certain exemptions from the general requirement to apply IFRS as effective for December 2011 year ends retrospectively. The Company has taken the following exemptions:

(a) IFRS 3 *Business Combinations* has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before January 1, 2010, the Company's date of transition.
(b) IFRS 2 *Share-based Payment* has not been applied to any equity instruments that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2009.
(c) The Company has elected under IFRS 1 *First-time Adoption of IFRS* to measure oil and gas assets at the date of transition at a deemed cost under Canadian GAAP.
(d) The Company has elected to apply the exemption from full retrospective application of decommissioning provisions as allowed under IFRS 1 *First Time Adoption of IFRS*. As such the Company has re-measured the provisions as at January 1, 2010 under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, and estimated the amount to be included in the retained earnings on transition to IFRS.

(ii) IFRS Balance Sheet as at January 1, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Accounts receivable		58,305	-	58,305
Due from private placement		2,728	-	2,728
Financial derivative instruments		8,683	-	8,683
Prepaid expenses		3,786	-	3,786
		73,502	-	73,502
Prepaid capital		955	-	955
Financial derivative instruments		1,254	-	1,254
Oil and gas assets		1,178,402	-	1,178,402
		1,180,611	-	1,180,611
		1,254,113	-	1,254,113
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		55,890	-	55,890
Distributions payable		13,790	-	13,790
Provision for future performance based compensation	(d)	2,001	1,394	3,395
		71,681	1,394	73,075
Long-term debt		435,000	-	435,000
Provision for future performance based compensation	(d)	1,041	(25)	1,016
Decommissioning provision	(c)	10,487	6,992	17,479
Deferred income taxes	(e)	123,421	68,486	191,907
		569,949	75,453	645,402
Unitholders' equity				
Unitholders' capital	(e)	500,407	812	501,219
Units to be issued		2,728	-	2,728
Retained earnings		99,749	(74,122)	25,627
Accumulated other comprehensive income	(e)	9,599	(3,537)	6,062
		612,483	(76,847)	535,636
		1,254,113	-	1,254,113

(ii) IFRS Balance Sheet as at June 30, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Cash		9,276	-	9,276
Accounts receivable		49,401	-	49,401
Financial derivative instruments		29,084	-	29,084
Inventory and prepaid expenses		5,635	-	5,635
		93,396	-	93,396
Financial derivative instruments		3,283	-	3,283
Oil and gas assets	(f)	1,223,607	9,037	1,232,644
		1,226,890	9,037	1,235,927
		1,320,286	9,037	1,329,323
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		38,281	-	38,281
Distributions payable		13,885	-	13,885
Provision for future performance based compensation	(d)	9,232	(2,986)	6,246
		61,398	(2,986)	58,412
Long-term debt		430,000	-	430,000
Provision for future performance based compensation	(d)	2,311	(249)	2,062
Decommissioning provision	(c)	11,133	10,590	21,723
Deferred income taxes	(e)	124,303	73,650	197,953
		567,747	83,991	651,738
Unitholders' equity				
Unitholders' capital	(e)	584,996	1,554	586,550
Units to be issued		994	-	994
Retained earnings		76,227	(64,681)	11,546
Accumulated other comprehensive income	(e)	28,924	(8,841)	20,083
		691,141	(71,968)	619,173
		1,320,286	9,037	1,329,323

(ii) IFRS Balance Sheet as at December 31, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Assets				
Current assets				
Cash		7,894	-	7,894
Accounts receivable		55,876	-	55,876
Due from private placement		12,423	-	12,423
Financial derivative instruments		25,247	-	25,247
Inventory and prepaid expenses		3,280	-	3,280
		104,720	-	104,720
Financial derivative instruments		2,664	-	2,664
Oil and gas assets	(f)	1,347,191	20,678	1,367,869
		1,349,855	20,678	1,370,533
		1,454,575	20,678	1,475,253
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		113,592	-	113,592
Dividends payable		15,825	-	15,825
Provision for future performance based compensation	(d)	5,567	(227)	5,340
		134,984	(227)	134,757
Long-term debt		355,000	-	355,000
Provision for future performance based compensation	(d)	1,452	(83)	1,369
Decommissioning provision	(c)	11,926	12,808	24,734
Deferred income taxes	(e)	112,567	2,043	114,610
		480,945	14,768	495,713
Shareholders' equity				
Shareholders' capital	(e)	754,493	1,338	755,831
Shares to be issued		17,285	-	17,285
Retained earnings		46,319	4,455	50,774
Accumulated other comprehensive income	(e)	20,549	344	20,893
		838,646	6,137	844,783
		1,454,575	20,678	1,475,253

(ii) Reconciliation of earnings and comprehensive income for the three months ended June 30, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Oil and gas sales		63,002	-	63,002
Realized gain on hedges		11,368	-	11,368
Royalties		(9,721)	-	(9,721)
Petroleum and natural gas sales, net		64,649	-	64,649
Expenses				
Operating		4,612	-	4,612
Transportation		1,578	-	1,578
General and administrative	(f)	1,075	(151)	924
Future performance based compensation	(d)	6,368	(3,277)	3,091
Interest		4,969	-	4,969
Accretion of decommissioning liability	(c)	-	168	168
Depletion and depreciation	(f)	21,906	(2,678)	19,228
		40,508	(5,938)	34,570
Earnings before taxes		24,141	5,938	30,079
Taxes				
Deferred income tax recovery	(e)	555	(250)	305
Earnings for the period		24,696	5,688	30,384
Other comprehensive income (loss)				
Change in unrealized gain (loss) on cash flow hedges	(e)	(1,344)	4,997	3,653
Realized (gain) loss on cash flow hedges		(11,368)	-	(11,368)
Comprehensive income for the period		11,984	10,685	22,669

(ii) Reconciliation of earnings and comprehensive income for the six months ended June 30, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Oil and gas sales		137,091	-	137,091
Realized gain on hedges		17,253	-	17,253
Royalties		(18,894)	-	(18,894)
Petroleum and natural gas sales, net		135,450	-	135,450
Expenses				
Operating		9,172	-	9,172
Transportation		3,013	-	3,013
General and administrative	(f)	2,911	(441)	2,470
Future performance based compensation	(d)	8,501	(4,604)	3,897
Interest		9,381	-	9,381
Accretion of decommissioning liability	(c)	-	346	346
Depletion and depreciation	(f)	42,319	(5,345)	36,974
Gains on divestitures	(f)	-	-	-
		75,297	(10,044)	65,253
Earnings before taxes		60,153	10,044	70,197
Taxes				
Deferred income tax recovery	(e)	1,418	(603)	815
Earnings for the year		61,571	9,441	71,012
Other comprehensive income (loss)				
Change in unrealized gain (loss) on cash flow hedges	(e)	36,578	(5,304)	31,274
Realized (gain) loss on cash flow hedges		(17,253)	-	(17,253)
Comprehensive income for the year		80,896	4,137	85,033

(ii) Reconciliation of earnings and comprehensive income for the year ended December 31, 2010

	Notes 17(iii)	Canadian GAAP	Effect of Transition to IFRS	IFRS
Revenue				
Oil and gas sales		275,081	-	275,081
Realized gain on hedges		44,345	-	44,345
Royalties		(33,405)	-	(33,405)
Petroleum and natural gas sales, net		286,021	-	286,021
Expenses				
Operating		18,415	-	18,415
Transportation		6,954	-	6,954
General and administrative	(f)	6,518	(2,880)	3,638
Performance based compensation	(d)	29,864	-	29,864
Future performance based compensation	(d)	3,978	(1,680)	2,298
Interest		20,057	-	20,057
Accretion of decommissioning liability	(c)	-	683	683
Depletion and depreciation	(f)	94,184	(10,414)	83,770
Gains on divestitures	(f)	-	(2,249)	(2,249)
		179,970	(16,540)	163,430
Earnings before taxes		106,051	16,540	122,591
Taxes				
Deferred income tax recovery	(e)	15,787	62,036	77,823
Earnings for the year		121,838	78,576	200,414
Other comprehensive income (loss)				
Change in unrealized gain (loss) on cash flow hedges	(e)	55,295	344	55,639
Realized (gain) loss on cash flow hedges		(44,345)	-	(44,345)
Comprehensive income for the year		132,788	78,920	211,708

(iii) Notes to the reconciliation of balance sheet, income statement and comprehensive income from Canadian GAAP to IFRS

(a) The Company has elected under IFRS 1 *First-time Adoption of IFRS* to measure oil and gas assets at the date of transition to IFRS on a deemed cost basis. The Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

(i) No exploration or evaluation assets were reclassified from the full cost pool to exploration and evaluation assets; and

(ii) All costs recognized under Canadian GAAP under the full cost pool were allocated to the producing assets and undeveloped proved properties on a pro rata basis using reserve volumes.

(b) The recognition and measurement of impairment differs under IFRS from Canadian GAAP. In accordance with IFRS 1 the Company performed an assessment of impairment for all property, plant and equipment and other corporate assets at the date of transition. The testing on transition to IFRS did not result in impairment.

(c) Under Canadian GAAP asset retirement obligations were discounted at a credit adjusted risk free rate. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted and the provision is discounted at a risk free rate. Upon transition to IFRS this resulted in a $7.0 million increase in the decommissioning provision with a corresponding decrease in retained earnings.

As a result of the change in the decommissioning provision, accretion expense for the three and six month periods ended June 30, 2010 and for the year ended December 31, 2010 was $0.2 million, $0.5 million and $0.7 million, respectively. In addition, under Canadian GAAP accretion of the discount was included in depletion and depreciation. Under IFRS it is included in accretion of decommissioning liability.

(d) Under Canadian GAAP, the Company recognized an expense related to their share-based payments on an intrinsic value basis. Under IFRS, the Company is required to recognize the expense using a fair value model and estimate a forfeiture rate. This increased provision for performance based compensation and decreased retained earnings at the date of transition by $1.4 million.

For the three and six month periods ended June 30, 2010 and year ended December 31, 2010 performance based compensation expense decreased by $3.3 million, $4.6 million and $1.7 million, respectively with a corresponding increase in retained earnings.

(e) Under IFRS it is required to account for the rate applicable to a trust rather than the rate applicable to a corporation. The reversal amounts related to the rate differential under the trust rate of 39% rather than the corporate rate of 25% which fully reversed in the comparative period. The result is that under IFRS the deferred tax liability at January 1, 2010 was $68.5 million higher than under Canadian GAAP with the offset a result of rate differential specific to the following three separate components.

First – The rate change on the tax pools of the Company is a $65.8 million reduction to retained earnings.
Second – The rate change on the Marked-to-Market of financial instruments is a $3.5 million to reduction to accumulated other comprehensive income.
Third – The rate change on the share issuance costs is a credit of $0.8 million to shareholders' capital.

After conversion to a Corporation on December 31, 2010 the rates applicable to the above would revert back to the 25% and an income inclusion in the period of $65.0 million substantially reversed the deferred tax liability and related account impacts.

(f) Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over total proved reserves, less undeveloped land. In addition depletion was calculated at the Canadian cost centre level under Canadian GAAP. IFRS requires depletion and depreciation to be calculated at a unit of account level.

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election as discussed in Note 17(i)(c).

For the three and six month periods ended June 30, 2010 and year ended December 31, 2010 the change in policy to deplete oil and natural gas interest on proved plus probable reserves, the inclusion of undeveloped land and component accounting resulted in a net decrease to depletion and depreciation of $2.7 million, $5.3 million and $10.4 million with a corresponding change to property, plant and equipment.

As a result of specific general and administrative recoveries guidance under IFRS, the company has capitalized additional costs for the three and six month periods ended June 30, 2010 and year ended December 31, 2010 by $0.2 million, $0.4 million and $2.9 million, respectively with a corresponding increase in retained earnings.

(iii) Adjustments to the statement of cash flows

The transition from Canadian GAAP to IFRS had no material impact on cash flows generated by the Company.

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

Auditors

Deloitte & Touche LLP

Solicitors

Burnet, Duckworth & Palmer LLP

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Union Bank, Canada Branch
BNP Paribas (Canada)
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