



## INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Peyto Exploration & Development Corp.:

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

### *Management's Responsibility for the Consolidated Financial Statements*

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

### *Auditor's Responsibility*

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

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

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

### *Opinion*

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Peyto Exploration & Development Corp. as at December 31, 2010 and 2009, and the results of operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants  
Calgary, Alberta  
March 8, 2011

# Peyto Exploration & Development Corp.

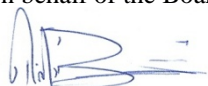
## Consolidated Balance Sheets

(\$000)

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

See accompanying notes

On behalf of the Board:



(signed) "Michael MacBean"  
Director



(signed) "Darren Gee"  
Director

## Peyto Exploration & Development Corp.

### Consolidated Statements of Earnings

(\$000 except per share amounts)

For the years ended December 31,

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

See accompanying notes

**Peyto Exploration & Development Corp.**

**Consolidated Statements of Comprehensive Income**

(\$000)

For the years ended December 31,

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

*See accompanying notes*

**Peyto Exploration & Development Corp.**

**Consolidated Statements of Retained Earnings and Accumulated Other  
Comprehensive Income**

(\$000)

For the years ended December 31,

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

*See accompanying notes*

## Peyto Exploration & Development Corp.

### Consolidated Statements of Cash Flows

(\$000)

For the years ended December 31,

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

See accompanying notes

# **Peyto Exploration & Development Corp.**

## **Notes to Consolidated Financial Statements**

December 31, 2010 and 2009

### **1. Nature of Operations**

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

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

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

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

### **2. Summary of Significant Accounting Policies**

These consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Because a precise determination of many assets and liabilities is dependent upon future events, the preparation of periodic financial statements necessarily involves the use of estimates and approximations. Accordingly, actual results could differ from those estimates. The consolidated financial statements have, in management’s opinion, been properly prepared within reasonable limits of materiality and within the framework of the Company’s accounting policies summarized below.

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

#### **Cash Equivalents**

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

#### **Joint operations**

The Company conducts a portion of its petroleum and natural gas exploration, development and production activities jointly with others and, accordingly, these consolidated financial statements reflect only the Company’s proportionate interest in such activities.

#### **Property, plant and equipment**

The Company follows the full cost method of accounting for its petroleum and natural gas properties. All costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities. All other general and administrative costs are expensed as incurred.

The Company evaluates its petroleum and natural gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties (“ceiling test”). The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves plus the cost of unproved properties, less

impairment, exceed the carrying value of the oil and gas assets. If the carrying value of the petroleum and natural gas properties is not determined to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves plus the cost of unproved properties, less impairment. The discounted cash flows are estimated using the future product prices and costs and are discounted using a risk-free rate.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20% or more, in which case a gain or loss would be recorded.

All costs of acquisition, exploration and development of petroleum and natural gas reserves (net of salvage value) and estimated costs of future development of proved undeveloped reserves are depleted and depreciated using the unit of production method based on estimated gross proved reserves as determined by independent engineers. For purposes of the depletion and depreciation calculation, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Costs of unproved properties are initially excluded from petroleum and natural gas properties for the purpose of calculating depletion. When proved reserves are assigned to the property or it is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Depreciation of gas plants and related facilities is calculated on a declining basis over a 20-year term. Office furniture and equipment are depreciated over their estimated useful lives at declining balance basis between 20% and 30% per year.

#### **Asset retirement obligations**

The Company records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit of production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

#### **Hedging**

The Company uses derivative financial instruments from time to time to hedge its exposure to commodity price fluctuations. The Company does not enter into derivative financial instruments for trading or speculative purposes. All derivative financial instruments are initiated within the guidelines of the Company's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into natural gas fixed price contracts, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract. For financial derivative contracts settling in future periods, a financial asset or liability is recognized in the balance sheet and measured at fair value, with changes in fair value recognized in other comprehensive income.

#### **Revenue recognition**

Petroleum and natural gas sales are recognized as revenue when title passes to purchasers, normally at pipeline delivery point for natural gas and at the wellhead for crude oil.

#### **Measurement uncertainty**

The timely preparation of the consolidated financial statements in conformity with Canadian generally accepted accounting principles requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

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

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

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

**Future income taxes**

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

**Financial Instruments**

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

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

**Derivative Instruments and Risk Management**

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

**Embedded Derivatives**

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

### 3. Pending Accounting Pronouncements

#### International Financial Reporting Standards ("IFRS")

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

### 4. Accounts Receivable

(\$000)	2010	2009
Accounts receivable – general	48,721	51,150
Accounts receivable – income taxes	7,155	7,155
	<b>55,876</b>	<b>58,305</b>

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

### 5. Property, Plant and Equipment

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

At December 31, 2010 costs of \$36.4 million (December 31, 2009 - \$26.6 million) related to undeveloped land have been excluded from the depletion and depreciation calculation.

The Company performed a ceiling test calculation at December 31, 2010 resulting in the undiscounted cash flows from proved reserves plus the cost of unproved properties, less impairment, exceeding the carrying value of petroleum and natural gas assets. The impairment test was calculated at December 31, 2010 using the following independent engineering consultant's forecasted prices:

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

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

### 6. Long-Term Debt

The Company has a syndicated \$625 million extendible revolving credit facility with a stated term date of April 30, 2011. The facility is made up of a \$20 million working capital sub-tranche and a \$605 million production line. The facilities are available on a revolving basis for a period of at least 364 days and upon the term out date may be extended for a further 364 day period at the request of the Company, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a further one year term, at the end of which time the facility would be due and payable. Outstanding amounts on this facility bear interest at rates determined by the Company's debt to earnings before interest, taxes, depreciation, depletion and

amortization (EBITDA) ratio that range from prime to prime plus 1.25% to 2.75% for debt to EBITDA ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank. The average borrowing rate for 2010 was 4.6% (2009 – 3.5%).

## 7. Asset Retirement Obligations

The total future asset retirement obligations are estimated by Management based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of its total asset retirement obligations to be \$11.9 million as at December 31, 2010 (2009 - \$10.5 million) based on a total future liability of \$39.6 million (2009 - \$36.0 million). These payments are expected to be made over the next 50 years. The Company's credit adjusted risk free rate of 7% and an inflation rate of 2% were used to calculate the present value of the asset retirement obligations.

The following table reconciles the change in asset retirement obligations:

(\$000)	2010	2009
<b>Balance, December 31, 2009</b>	<b>10,487</b>	9,479
Increase in liabilities relating to investing activities	696	341
Accretion expense	743	667
<b>Balance, December 31, 2010</b>	<b>11,926</b>	10,487

## 8. Shareholders' Capital and Unitholders' Capital

**Authorized:** Unlimited number of voting common shares or units

### Issued and Outstanding

Trust Units (no par value) (\$000)	Number of Units	Amount
<b>Balance, December 31, 2008</b>	<b>105,920,194</b>	<b>410,233</b>
Trust units issued	9,000,000	94,500
Trust units issuance costs (net of tax)	-	(4,326)
<b>Balance, December 31, 2009</b>	<b>114,920,194</b>	<b>500,407</b>
Trust units issued by private placement	196,420	2,728
Trust units issued	13,880,500	218,704
Trust units issuance costs (net of tax)	-	(8,206)
Trust units issued pursuant to DRIP	746,079	10,558
Trust units issued pursuant to OTUPP	2,132,189	30,302
Exchange for common shares pursuant to the Arrangement ( <i>Note 1</i> )	(131,875,382)	(754,493)
<b>Balance, December 31, 2010</b>	<b>-</b>	<b>-</b>

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

### Units Issued

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

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

On June 26, 2009, Peyto closed an offering of 9,000,000 trust units at a price of \$10.50 per trust unit, receiving net proceeds of \$90.2 million (net of issuance costs).

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

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

#### **Common Shares Issued**

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

#### **Common Shares to be Issued**

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

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

#### **Per Share or Per Units Amounts**

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

#### **Comprehensive Income**

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

### **9. Accumulated Distributions**

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

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

<sup>(1)</sup> Distributions per trust unit reflect the per trust unit amounts declared monthly to Unitholders.

## Retained Earnings and Distributions

(\$000)	2010	2009
<b>Retained earnings, beginning of year</b>	<b>1,072,209</b>	919,435
Earnings for the year	<b>121,838</b>	152,774
Total retained earnings	<b>1,194,047</b>	1,072,209
Total accumulated distributions	<b>(1,147,728)</b>	(972,460)
<b>Retained earnings, end of year</b>	<b>46,319</b>	99,749

## 10. Operating Expenses

The Company's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party natural gas reduces operating expenses.

(\$000)	2010	2009
Field expenses	<b>28,960</b>	27,487
Processing and gathering income	<b>(10,545)</b>	(10,751)
<b>Total Operating expenses</b>	<b>18,415</b>	16,736

## 11. General and Administrative Expenses

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

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

## 12. Performance Based Compensation

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

### Reserve Based Component

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

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

### Market Based Component

Under the market based component, rights with a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 6% of the total number of common shares outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. Compensation is calculated as the number of vested rights multiplied by the total of the market appreciation (over the price at the date of grant) and associated dividends of a share for that period. The 2010 market based component was based on i) 1.5 million vested rights at an average grant price of \$16.45, average cumulative distributions of \$4.67, ii) 0.5 million vested rights at an average grant price of \$9.53, average cumulative distributions of \$2.91 and a five day weighted average closing price of \$18.95 and iii) 0.7 million vested rights at an average grant price of \$13.49, average cumulative distributions of \$1.44 and a ten day weighted average price of \$18.83.

The total amount expensed under these plans was as follows:

(\$000)	2010	2009
Market based compensation	<b>21,236</b>	4,540
Reserve value based compensation	<b>8,628</b>	540
Total	<b>29,864</b>	5,080

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

### 13. Future Income Taxes

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

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

At December 31, 2010 the Company has tax pools of approximately \$884.0 million (December 31, 2009 - \$676.1 million) available for deduction against future income. The Company has approximately \$nil in unrecognized future

income tax assets (December 31, 2009 - \$6.0 million) and approximately \$0.3 million in loss carryforwards (December 31, 2009 - \$nil) available to reduce future taxable income.

## 14. Financial Instruments and Risk Management

### Financial Instrument Classification and Measurement

Financial instruments of the Company carried on the Consolidated Balance Sheet are carried at amortized cost with the exception of cash and financial derivative instruments, specifically fixed price contracts, which are carried at fair value. There are no significant differences between the carrying value of financial instruments and their estimated fair values as at December 31, 2010.

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

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

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

### Fair Values of Financial Assets and Liabilities

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

### Market Risk

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

### Commodity Price Risk Management

The Company is a party to certain derivative financial instruments, including fixed price contracts. The Company enters into these contracts with well established counterparties for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of petroleum and natural gas prices. The Company believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Company's firm commitment or forecasted transactions and the underlying basis of the instruments correlate highly with the Company's exposure. A summary of contracts outstanding in respect of the hedging activities at December 31, 2009 is as follows:

Description	Notional <sup>(1)</sup>	Term	Effective Rate	Fair Value Level	Asset as at December 31, 2010	Asset as at December 31, 2009
Natural gas financial swaps - AECO	24.01 GJ <sup>(2)</sup>	2011- 2012	\$5.07/GJ	Level 1	27,911	9,936

<sup>(1)</sup> Notional values as at December 31, 2010 <sup>(2)</sup> Millions of gigajoules

<b>Natural Gas Period Hedged</b>	<b>Type</b>	<b>Daily Volume</b>	<b>Price (CAD)</b>
November 1, 2009 to March 31, 2011	Fixed Price	5,000 GJ	\$6.20/GJ
November 1, 2009 to March 31, 2011	Fixed price	5,000 GJ	\$5.81/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	\$5.28/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	\$5.29/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	\$5.555/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	\$5.70/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	\$4.55/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	\$5.67/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	\$5.82/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	\$8.91/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	\$9.15/GJ
November 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	\$4.10/GJ
April 1, 2011 to October 31, 2011	Fixed Price	5,000 GJ	\$3.50/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	\$6.20/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	\$5.00/GJ
April 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	\$5.12/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	\$4.05/GJ
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	\$4.15/GJ
November 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	\$4.50/GJ

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

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

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

#### **Interest rate risk**

The Company is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Company has not entered into any agreements to manage this risk. If interest rates applicable to floating rate debt were to have increased by 100 bps (1%) it is estimated that the Company's earnings for the year ended December 31, 2010 would decrease by \$4.2 million. An opposite change in interest rates will result in an opposite impact on earnings.

#### **Credit Risk**

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

Industry standard dictates that commodity sales are settled on the 25<sup>th</sup> day of the month following the month of production. The Company generally extends unsecured credit to purchasers, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit. The Company has not previously experienced any material credit losses on the collection of accounts receivable. Of the Company's revenue for the year ended December 31, 2010, approximately 76% was received from five companies (20%, 18%, 17%, 11% and 10%) (December 31, 2009 – 55%, three companies (21%, 20% and 14%). Of the Company's accounts receivable for the year ended December 31, 2010, approximately 31% was receivable from three companies (11%, 10% and 10%) (December 31, 2009 – the Company had no significant accounts receivable from any one customer). The maximum exposure to credit risk is

represented by the carrying amount on the consolidated balance sheet. There are no material financial assets that the Company considers past due and no accounts have been written off.

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

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

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

### **Liquidity Risk**

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

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

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

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

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

<sup>(1)</sup>Revolving credit facility renewed annually (see Note 7)

## **15. Capital Disclosures**

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

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

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

(\$000s)	<b>December 31, 2010</b>	December 31, 2009
Shareholders' equity	<b>838,646</b>	612,483
Long-term debt	<b>355,000</b>	435,000
Working capital deficit (surplus) <sup>(1)</sup>	<b>30,264</b>	(1,822)
	<b>1,223,910</b>	1,045,661

<sup>(1)</sup>Current assets less current liabilities (includes unrealized hedging asset of \$25.2 million (2009 - \$8.7 million))

## 16. Supplemental Cash Flow Information

Changes in non-cash working capital balances (\$000)	<b>2010</b>	<b>2009</b>
Accounts receivable	<b>2,429</b>	7,357
Due from private placement	<b>(9,695)</b>	-
Prepaid expenses	<b>507</b>	(420)
Accounts payable and accrued liabilities	<b>57,703</b>	7,035
Distributions payable	<b>2,035</b>	(2,098)
Provision for future performance based compensation	<b>3,977</b>	3,042
	<b>56,956</b>	14,916
Attributable to operating activities	<b>22,297</b>	4,060
Attributable to financing activities	<b>(7,660)</b>	(2,098)
Attributable to investing activities	<b>42,319</b>	12,903
	<b>56,956</b>	14,916
	<b>2010</b>	<b>2009</b>
Cash interest paid during the year	<b>20,057</b>	16,527
Cash taxes paid during the year	-	-

## 17. Contingencies and Commitments

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

(\$000)	<b>December 31, 2010</b>
2011	1,043
2012	1,043
2013	1,043
2014	1,043
	<b>4,172</b>

### Contingent Liability

From time to time, Peyto is the subject of litigation arising out of its day-to-day operations. Damages claimed pursuant to such litigation, including the litigation discussed below, may be material or may be indeterminate and the outcome of such litigation may materially impact Peyto's financial position or results of operations in the period of settlement. While Peyto assesses the merits of each lawsuit and defends itself accordingly, Peyto may be required to incur significant expenses or devote significant resources to defending itself against such litigation. These claims are not currently expected to have a material impact on Peyto's financial position or results of operations.

Peyto has been named in a Statement of Claim issued by Canadian Natural Resources Limited and affiliates ("CNRL"), claiming \$13 million in damages for alleged breaches of duty as operator of jointly owned properties, and an interim and permanent injunction to prevent Peyto from proceeding with the completion of a well on those

properties. CNRL alleges that Peyto failed to take proper steps as operator of a joint well (the "Well") on lands that offset 100% Peyto owned lands. Peyto has filed a Statement of Defense defending the allegations set forth in the Statement of Claim. The injunction claimed by CNRL was to prevent Peyto from completing the Well at a target location which had been agreed upon by both parties. Although claimed in the Statement of Claim, CNRL did not apply for an interim injunction, and Peyto completed the Well as planned, but no commercial production was obtained. Affidavits of Records were filed in July, 2006 but CNRL had taken no steps to move the matter forward until February 14, 2007 when it proposed to amend its Statement of Claim to add a subsidiary as an additional Plaintiff and to particularize further its allegations. Accordingly, it remains to be seen whether CNRL will proceed with the action. If the action goes ahead, Peyto intends to defend itself vigorously. Although the outcome of this matter is not determinable at this time, Peyto believes that this claim will not have a material adverse effect on the Company's financial position or results of operations.

**18. Related Party Transactions**

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

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