PEYTO

Energy Trust

2003

Annual Report

Peyto Energy Trust ("Peyto") is a leader in the exploration and development of natural gas in Canada. As with previous years, Peyto's 2003 year end results rank at the top of value and return in the Canadian energy sector:

- High return per share/unit on investment, calculated per year and compounded annually - 5 year 162%, 3 year 127% , 1 year 153%
- Long reserve life - Proved 12.5 years, Proved Plus Probable 18.8 years
- Low operating costs - $1.86/boe
- Low base general and administrative costs - $0.18/boe
- High cash flow netback - $30.31/boe
- Strong production growth - 55% year over year, 55% per diluted trust unit
- Strong cash flow growth - 142% year over year, 143% per diluted trust unit
- Low finding, development & acquisition costs before future development capital ("FDC") - Proved $4.57/boe, Proved Plus Probable $3.08/boe
- Low finding, development & acquisition costs including FDC - Proved $6.58/boe, Proved Plus Probable $6.46/boe
- High recycle ratio including FDC - Proved 4.6, Proved Plus Probable 4.7
- High reserve replacement ratio - Proved 610%, Proved Plus Probable 900%
- High operatorship – over 95% of production
- Low cash distribution ratio - 50% of 4th quarter 2003 cash flow

The Peyto team's proven expertise for finding and developing long life high quality gas projects has set it apart from the rest of the Canadian energy sector. By design, our assets are concentrated in the Deep Basin, Alberta's premier gas exploration area. Within the Deep Basin, there is an abundance of undeveloped resources available for pursuit using Peyto's proven formula. The combination of our expertise and our high quality asset base allows Peyto to offer investors true growth on a per unit basis.

We are proud to present our operating and financial results for the fourth quarter and full fiscal year 2003.

	3 Months Ended Dec. 31		%	**12 Months Ended Dec. 31**		%
	2003	2002	Change	**2003**	2002	Change
Operations						
Production						
Natural gas (mcf/d)	**73,013**	50,556	*44*	**65,015**	42,254	*54*
Oil & NGLs (bbl/d)	**3,104**	2,349	*32*	**2,904**	1,823	*59*
Barrels of oil equivalent (boe/d @ 6:1)	**15,273**	10,775	*42*	**13,740**	8,865	*55*
Product prices						
Natural gas ($/mcf)	**6.93**	5.90	*17*	**7.51**	4.63	*62*
Oil & NGLs ($/bbl)	**35.22**	36.52	*-4*	**36.62**	32.06	*14*
Operating expenses ($/boe)	**2.19**	1.12	*96*	**1.86**	1.37	*36*
Field netback ($/boe)	**30.48**	25.15	*21*	**31.43**	20.45	*54*
Base general & administrative expenses ($/boe)	**0.10**	1.23	*-92*	**0.18**	0.52	*-65*
Interest expense ($/boe)	**0.80**	0.94	*-15*	**0.94**	0.82	*15*

	3 Months Ended Dec. 31		%	12 Months Ended Dec. 31		%
	2003	2002	Change	**2003**	2002	Change
Financial ($000, except per unit/share)						
Revenue	**56,589**	35,354	*60*	**216,931**	92,709	*134*
Royalties (net of ARTC)	**10,688**	9,311	*15*	**49,996**	22,101	*126*
Cash flow	**41,371**	23,746	*74*	**151,407**	62,503	*142*
Cash flow per unit/share	**0.91**	0.55	*65*	**3.41**	1.45	*135*
Cash distributions	**20,428**	-	-	**40,856**	-	-
Cash distributions per unit	**0.45**	-	-	**0.90**	-	-
Percentage of cash flow distributed	**50%**	-	-	**27%**	-	-
Earnings	**6,166**	10,310	*-40*	**48,418**	28,554	*70*
Earnings per unit/share	**0.14**	0.24	*-42*	**1.09**	0.66	*65*
Capital expenditures	**43,763**	37,627	*16*	**139,423**	112,551	*24*
Weighted average trust units/shares outstanding	**45,395,122**	43,340,812	*5*	**44,430,031**	42,978,340	*3*

	As at December 31		%
	2003	2002	Change
Working capital deficit	**19,981**	30,985	*-36*
Bank debt	**150,000**	80,000	*88*
Unitholders' equity	**117,638**	71,066	*77*
Total assets	**414,260**	242,166	*71*

Cash Flow

Management uses cash flow to analyze operating performance. In order to facilitate comparative analysis cash flow is defined throughout this report as earnings before bonus, non-cash and non-recurring expenses. As presented, cash flow does not have any standardized meaning prescribed by Canadian GAAP.

	12 Months Ended Dec. 31	
	2003	2002
Earnings	**48,418**	28,554
Items not requiring cash:		
Non-cash provision for bonuses	**12,475**	1,099
Future income tax expense	**5,179**	20,627
Depletion, depreciation & site	**23,724**	12,223
Non-recurring items:		
Trust reorganization costs	**44,206**	-
Market and reserves based bonus	**17,405**	-
Cash flow	**151,407**	62,503

Reserves

Proved developed reserves at year-end increased to 59.2 million barrels of oil equivalent ("boe", natural gas converted on a 6:1 basis throughout) from 44.4 million boes in 2002. In conjunction with the new reserve policy, 10.6 million boes have now been assigned to the proved undeveloped category. These proved undeveloped reserves are a continuation of the high quality resource that makes up our proved producing reserves and are all scheduled to be developed by the end of 2004. The proved plus probable reserves increased by 40.3 million boes from 64.8 in 2002 to 105.1 million boes in 2003. As in previous years, the majority of the probable reserves booked at the end of 2003 represent low risk gas locations that can be developed in the next year and a half. The net present value ("NPV") discounted at 8% of Peyto's proved plus probable additional petroleum and natural gas assets increased 20% from $913.8 million to $1.1 billion in 2003. The following table summarizes Peyto's reserves and the discounted net present value of future cash flow before income tax, using variable pricing, at December 31, 2003.

				Net Present Value ($000) Discounted at		
Reserve Category	**Gas (mmcf)**	**Oil & NGL (mstb)**	**BOE 6:1 (mstb)**	**8%**	**10%**	**12%**
Proved Producing	251,165	11,961	53,822	665,490	597,637	544,549
Proved Non-producing	26,305	1,041	5,425	53,332	47,218	42,510
Proved Undeveloped	49,151	2,381	10,573	94,498	80,661	69,597
Total Proved	326,621	15,383	69,820	813,320	725,516	656,656
Probable Additional	167,527	7,330	35,251	283,281	237,808	203,635
Proved + Probable Additional	494,148	22,713	105,071	1,096,601	963,324	860,291

Note: Based on the Paddock Lindstrom & Associates report effective December 31, 2003

Performance Ratios	**Proved Developed**	**Total Proved**	**Proved + Probable**
Reserve life index (years)			
2003 average production – 13,740 boe/d	11.8	13.9	21.0
Q4 2003 average production – 15,273 boe/d	10.6	12.5	18.8
Finding, development and acquisition costs before future development capital ($/boe)			
2003	7.01	4.57	3.08
2002	5.51	5.51	4.42
3 year average	5.78	4.86	3.45
Finding, development and acquisition costs including future development capital ($/boe)			
2003	7.70	6.58	6.46
2002	5.64	5.64	6.82
3 year average	6.03	5.79	5.07
2003 reserve replacement ratio	3.9	6.1	9.0
Recycle ratio before future development capital			
2003	4.3	6.6	9.8
3 year average	4.4	5.3	7.4
Recycle ratio including future development capital			
2003	3.9	4.6	4.7
3 year average	4.2	4.4	5.0

- The reserve life index can be calculated using various methodologies. We believe the most accurate way to look at the reserve life index is by dividing the proved developed reserves by the actual fourth quarter average production. In our opinion, for comparative purposes the proved developed reserve life will provide the best measure of sustainability.
- Finding, development and acquisition (“FD&A”) costs are used as a measure of capital efficiency and are calculated by dividing the capital costs for the period by the change in the reserves, including revisions, for the same period. Prior to NI 51-101, FD&A costs were calculated excluding future development capital (“FDC”). Both methods of calculating FD&A costs have been provided in order to facilitate comparisons with previous years.
- Peyto’s reserve replacement ratio is calculated by dividing the yearly change in reserves, including revisions and before production by the actual annual production.
- The recycle ratio is calculated by dividing the cash flow by the FD&A costs for the period. In our opinion, it is the best overall measure of investment performance as it takes into consideration the value of the producing barrel and the cost to replace it. The new reserve policy has made the recycle ratio more meaningful for all the categories because the FD&A costs now include the future development capital.

National Instrument 51-101 Cautionary Statements

The Canadian Securities Administrators have implemented new standards of disclosure for reporting issuers engaged in upstream oil and gas activities effective December 31, 2003. The new disclosure standards referred to as National Instrument ("NI") 51-101 establish a regime of continuous disclosure for oil and gas companies and include specific reporting requirements.

- Peyto's year-end reserve report summarized herein is compliant with NI 51-101. Under NI 51-101's revised reserve definitions and evaluation standards, proved plus probable reserves represent a "best estimate" and hence are compared to prior years' "established" reserves which were comprised of proved plus 50 percent of probable reserves.
- The term “boes” may be misleading particularly if used in isolation, a boe conversion ratio of 6 mcf : 1 barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
- It should not be assumed that the discounted net present values represent the fair market value of the reserves.
- The estimate of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.
- The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Capital Expenditures

Net capital expenditures for 2003 totaled $139.4 million. Exploration and development related activity represented $111.6 million or 80% of the total, while expenditures on facilities, gathering systems and equipment totaled $23.1 million or 17% of the total. The following table summarizes capital expenditures for the year.

Capital Expenditures	**2003 ($000)**	**% of Total**	**Since Inception ($000)**	**% of Total**
Land	3,063	*2*	11,414	*3*
Seismic	2,026	*1*	6,986	*2*
Drilling – Exploratory & Development	109,621	*79*	259,841	*68*
Production Equipment, Facilities & Pipelines	23,126	*17*	76,526	*20*
Acquisitions & Dispositions	1,500	*1*	27,549	*7*
Office Equipment	87	-	372	-
Total	139,423	*100*	382,687	*100*

Fourth Quarter Review

Daily production for the three months ended December 31, 2003 averaged 73 mmcf of natural gas and 3,104 barrels of oil and natural gas liquids. Our production gains increased cash flow from $23.7 million in 2002 to $41.4 million in 2003. Natural gas prices increased by 17% averaging $6.93 per mcf, oil and natural gas liquids prices decreased 4% averaging $35.22 per barrel. The high heating value of our gas resulted in a 17% premium when converted from gigajoules at the AECO price hub to mcf at the plantgate. Operating costs averaged $2.19 per boe. Capital expenditures for the quarter totaled $43.7 million with drilling projects continuing at record levels.

Trust Bonus Plan

The total bonus paid pursuant to the Trust's bonus plan adopted with the trust conversion was $17.4 million. This bonus represents 3% of the 166% annualized return that unitholders realized in the market during the first six months as a trust. A non-cash provision of $12.4 million for future compensation expense related to unvested rights was recorded in 2003. We are confident that Peyto's compensation program is aligned with the unitholders' objectives. In an effort to be transparent and tax efficient for the unitholders, the bonuses are paid in cash. A detailed discussion of our market and reserve based bonus plans is available on our website.

Subsequent to the bonus payment, a private placement of 330,150 trust units was completed to Peyto employees for proceeds of $9.0 million. Over 85% of the after tax bonus was reinvested by the employees back into units at an undiscounted weighted year end market price of $27.30/share. All senior executives of Peyto have significant holdings of Peyto trust units.

Over the past three years, Peyto has been able to fund our growth internally without the need to issue equity. All equity issues over that period have been done to the Peyto team at market prices in conjunction with our belief to further the alignment with unitholders.

Distributions

Cash distributions of $0.15 per unit per month to unitholders commenced with the July distribution being paid on August 15, 2003. Accumulated distributions for 2003 totaled $40,855,610 or $0.90 per unit. During the fourth quarter, distributions represented 50% of cash flow reflecting our high cash reinvestment ratio.

The financial and operational results set out herein, continue to reflect the success of our growth strategy. We are pleased to be in a position to increase our distributions while still maintaining aggressive growth plans for 2004. Effective with the April 2004 production month, cash distributions will be increased by 13 percent or $0.02 per unit per month for a total of $0.17 per unit to be distributed on May 14, 2004.

Activity Update

To date in 2004, Peyto has brought on stream 20 gross (12 net) gas wells and has drilled and cased 13 gross (9.7 net) new locations. Peyto currently has 6 drilling rigs active in its core areas. Peyto's new gas processing plant in the Smoky/Kakwa area is now operational. This 100% Peyto owned facility along with ongoing expansion of the Sundance plant and gathering system have allowed production to recently surge to over 18,000 boe per day. Although Peyto's new core area has seasonal access restrictions, the drilling activity planned for the remainder of 2004 should allow us to maintain this new level of production.

Outlook

Capital expenditures for 2004 are expected to be between $110 million and $160 million. The majority of the 2004 capital program will involve drilling, completion and tie-in of low risk development gas wells adjacent to existing infrastructure in Peyto's two core areas. These expenditures will be funded with a combination of cash flow, working capital, equity and bank lines. As a result of the growth in value realized in 2003, bank lines have now been increased by 28 percent to $230 million.

We have now completed our fifth consecutive year of exploration and development activity. Our results clearly indicate that our strategy has been successful. We believe our strategy will continue to deliver superior performance to unitholders for many years to come. If you are interested in the company and willing to invest some of your time to understand our success and our future plans we would suggest that you visit Peyto's website at www.peyto.com where you will find a current presentation, financial and historical news releases and an updated insider trading summary.

Don T. Gray
President and Chief Executive Officer
March 10, 2004

Management's Discussion and Analysis

The consolidated financial statements for the Trust are reported on a continuity of interests basis and include the financial results of Peyto to June 30, 2003 and the Trust from that date forward. As the Trust was created through a Plan of Arrangement the historical results of Peyto will represent the comparative financial results of the Trust.

Gross revenues totaled $216.9 million for the year 2003, an increase of 134 percent from $92.7 million in 2002. This increase is a result of higher production volumes in combination with higher commodity prices. The price of natural gas averaged $7.51 per mcf for the year 2003 up 62 percent from $4.63 per mcf in 2002. Oil and natural gas liquids prices averaged $36.62 per barrel in 2003 up 14 percent from $32.06 per barrel in 2002.

A successful drilling program resulted in natural gas production for the year increasing by 54 percent to 65.0 mmcf per day in 2003 from 42.2 mmcf per day in 2002. Oil and natural gas liquids production increased by 59 percent to 2,904 barrels per day in 2003 from 1,823 barrels per day in 2002. Production for the year averaged 13,740 barrels of oil equivalent ("boe", natural gas converted on a 6:1 basis) per day, an increase of 55 percent from 8,865 boe per day for 2002.

2003 royalties, net of Alberta Royalty Tax Credit (ARTC), increased by 126 percent to $49.9 million from $22.1 million in 2002 due to higher gross revenues associated with increased production volumes. The 2003 average royalty rate was 23 percent compared to 24 percent for 2002.

Increased production volumes caused operating costs to rise to $9.3 million in 2003 from $4.4 million in 2002. On a barrel of oil equivalent basis, operating costs increased to $1.86 per boe in 2003 from $1.37 per boe in 2002 due to higher volumes being processed through third party facilities in new areas and limited gathering and processing capacity in the Sundance field. Operating costs are comprised of field expenses and natural gas transportation costs net of income generated by the processing and gathering of joint venture gas. On a per boe basis, field expenses represent $1.99 per boe, transportation $0.56 per boe and processing and gathering income a recovery of $0.69 per boe.

General and administrative expenses decreased by 46 percent to $0.9 million for 2003 from $1.7 million in 2002. On a boe basis, general and administrative expenses decreased by 65 percent to $0.18 per boe in 2003 from $0.52 per boe in 2002. This reduction was the result of the increase in production volumes while maintaining a similar level of staff.

Trust reorganization costs of $44.2 million were incurred in 2003 which included $40.9 million for the cash payout of stock options, $1.8 million for bonuses paid upon the cancellation of Peyto's former bonus plan and $1.5 million for financial advisory, accounting and legal fees and the preparation and printing of the Information Circular used in connection with to the Plan of Arrangement.

Upon completion of the trust conversion, a cash bonus plan was adopted made up of market and value based components. The market based component is calculated based on the market appreciation of a pre-determined number of units and associated cash distributions over a three year period. Under the value component, the bonus pool will be comprised of 3% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and distributions, of proved producing reserves calculated using a discount rate of 8%. The intent of the plan was to provide incentive to officers, employees and key consultants to contribute to the future success of the Trust, thus enhancing the value of the units for the benefit of all the unitholders of the Trust. The total cash compensation under these plans for the year ended December 31, 2003 equaled $17,405,380 (2002 - $nil). A non-cash provision for future compensation expense of $12,475,098 (2002 - $nil) was recorded related to unvested rights.

Financing charges for 2003 were $4.7 million up from $2.7 million in 2002. The increase was the result of higher debt levels associated with the 2003 capital expenditure program in combination with commitment and legal fees of $0.6 million incurred related to the Trust's $180 million bank line. On a per boe basis, interest charges were $0.94 per boe for 2003 compared to $0.82 per boe in 2002.

Depreciation, depletion and site restoration expenses were $23.7 million for 2003 compared to $12.2 million for 2002 as a direct result of the increased asset base and production volumes. On a per boe basis, the average depreciation, depletion and site restoration rate increased to $4.73 in 2003 from $3.78 in 2002.

The provision for future income tax decreased to $5.2 million in 2003 from $20.6 million in 2002 due to the tax efficiency of both the trust and bonus plan structure.

The 55% increase in production volumes caused funds from operations for 2003 to increase to $89.8 million compared with $62.5 million in 2002. Higher average natural gas prices caused the field netback for the period to increase from $20.45 per boe in 2002 to $31.43 per boe in 2003. Earnings for 2003 were $48.4 million or $1.09 per unit compared with $28.6 million in 2002 or $0.66 per share.

Liquidity and Capital Resources

For the year ended December 31, 2003, the Trust incurred net capital expenditures of $139.4 million. Capital expenditures during 2003 were comprised of $111.6 million for exploration and development, $23.1 million for facilities, gathering systems and equipment and $4.6 million for acquisitions and land. Capital expenditures for 2003 were funded by cash flow, working capital, long term debt and equity. At December 31, 2003, the Trust's working capital deficiency and long term debt totaled $174.9 million, resulting in a net debt to running cash flow ratio of 1.1:1 based on annualized fourth quarter cash flow. Effective December 31, 2003 the Trust completed a private placement of 330,150 trust units to employees and consultants for proceeds of $9,013,095. The trust units were issued on January 2, 2004.

The second half of 2003 generated funds available for distribution as follows:

	$
Funds from operations	59,848,044
Funds from issuance of trust units	38,887,825
Funds drawn from bank line and working capital	22,163,219
Funds available for distribution and capital expenditures	120,899,088
Capital expenditures	(80,043,478)
Funds available for distribution	40,855,610

Outlook

Management expects the combination of current bank lines, cash flow from operations and equity to be sufficient to support Peyto's 2004 capital expenditure program anticipated to be between $110 and $160 million. In 2004, primarily all of Peyto's capital expenditures are discretionary focused on exploration, development and acquisition activity. The majority of these expenditures will be employed to drill, complete and tie-in low risk development gas wells adjacent to Peyto's existing infrastructure. Peyto has the flexibility to match planned capital expenditures to actual cash flow.

Peyto currently has a $180 million credit facility that bears interest at rates determined by the Trust's debt to cash flow ratio and does not require any principal repayments in 2004. The Trust settles sales receivables and trade payables in accordance with normal industry practices. Working capital liquidity is maintained through drawing and repaying the bank facilities. Subsequent to year end, the Trust's credit facility was increased to $230 million.

Business Risks

All companies in the Canadian oil and natural gas industry are exposed to a number of business risks, some of which are beyond their control. These risks can be categorized as operational, financial and regulatory.

Operational risks include finding and developing oil and natural gas reserves on an economic basis, reservoir production performance, product marketing , hiring and retaining employees and accessing contract services on a cost effective basis. By employing a team of highly qualified staff, providing a compensation system that rewards above average performance and developing strong long-term relationships with contract service providers, these risks are mitigated. The Trust maintains an insurance program consistent with industry practice to protect against destruction of assets, well blowouts, pollution and other business interruptions. We also maintain a geologically diverse, but geographically concentrated prospect inventory, undertake a large drilling program and use proved technology where appropriate to minimize the cost of finding and developing oil and natural gas reserves.

Financial risks include commodity prices, interest rates and the CDN/US exchange rate, all of which are largely beyond Peyto's control. Peyto's approach to management of these risks is to maintain a prudent level of debt, a low cost structure, enter into certain fixed price, physical delivery, commodity-based contracts and use its strong financial position to fund exploration and development activities and acquisitions through fluctuations in these variables.

Peyto is also subject to various regulatory risks, many of which are beyond our control. We take a proactive approach with respect to environmental and safety matters such as maintaining an environmental and safety program whereby major facilities are regularly audited. An operational emergency response plan is in place and is in compliance with current environmental legislation.

Business Prospects

Oil and natural gas are commodities affected by global and regional events of an economic, political and environmental nature. Such events can impact the price of the commodity in that either security of supply or demand for the product is affected to varying degrees. The outlook for prices, in turn, has a major influence on levels of competition and capital investment in the business. In 2003 oil prices strengthened but continued to be volatile. Peyto believes that oil prices will continue to be volatile in 2004. Natural gas prices have remained strong throughout 2003. Given this outlook, Peyto believes that capital investment and competition for land, acquisitions and services will increase in 2004. Peyto anticipates relative stability with respect to exchange and interest rates, although Peyto has a low sensitivity to these matters.

Quarterly Information

	2003				2002
	Q4	Q3	Q2	Q1	Q4
Operations					
Production					
Natural gas (mcf/d)	**73,013**	66,827	62,577	57,452	50,556
Oil & NGLs (bbl/d)	**3,104**	2,948	2,870	2,689	2,349
Barrels of oil equivalent (boe/d @ 6:1)	**15,273**	14,086	13,299	12,265	10,775
Average product prices					
Natural gas ($/mcf)	**6.93**	7.02	7.80	8.50	5.90
Oil & natural gas liquids ($/bbl)	**35.22**	33.86	33.94	44.23	36.52
Average operating expenses ($/boe)	**2.19**	2.20	1.88	1.01	1.12
Field netback ($/boe)	**30.48**	29.24	31.53	35.09	25.15
General & administrative expense ($/boe)	**0.10**	0.13	0.36	0.14	1.23
Interest expense ($/boe)	**0.80**	1.33	0.81	0.81	0.94
Financial ($000 except per unit)					
Revenue	**56,589**	52,365	53,307	54,670	35,354
Royalties (net of ARTC)	**10,688**	11,622	12,866	14,820	9,311
Cash flow	**41,371**	35,882	36,845	37,309	23,746
Cash flow per unit/share	**0.91**	0.79	0.85	0.86	0.55
Cash distributions	**20,428**	20,428	-	-	-
Cash distributions per unit	**0.45**	0.45	-	-	-
Percentage of cash flow distributed	**50%**	57%	-	-	-
Earnings	**6,166**	25,398	(1,642)	18,495	10,310
Earnings per unit/share	**0.14**	0.56	(0.04)	0.43	0.24
Capital expenditures	**43,763**	36,280	18,895	40,486	37,627
Weighted average trust units/shares outstanding	**45,395,122**	45,395,122	43,451,522	43,446,337	43,340,812

AUDITORS' REPORT

To the Unitholders of
Peyto Energy Trust

We have audited the consolidated balance sheets of **Peyto Energy Trust** as at December 31, 2003 and 2002 and the consolidated statements of earnings and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Calgary, Canada
February 13, 2004

Chartered Accountants

Peyto Energy Trust

CONSOLIDATED BALANCE SHEETS

(Note 1)

As at December 31,

	2003 **$**	2002 $
ASSETS		
Current		
Cash	**20,591,218**	205,558
Accounts receivable *(Note 11)*	**41,110,278**	18,860,110
Due from private placement (Note 5)	**9,013,095**	-
Prepaids and deposits	**5,132,281**	894,553
	75,846,872	19,960,221
Property, plant and equipment *(Notes 3 and 4)*	**338,413,384**	222,206,233
	414,260,256	242,166,454
LIABILITIES AND UNITHOLDERS' EQUITY		
Current		
Accounts payable and accrued liabilities	**81,426,984**	50,778,415
Capital taxes payable	**76,726**	166,922
Cash distributions payable	**6,809,268**	-
Provision for future market based bonus *(Note 8)*	**7,515,119**	-
	95,828,097	50,945,337
Long-term debt *(Note 4)*	**150,000,000**	80,000,000
Provision for future market based bonus *(Note 8)*	**4,959,979**	-
Future site restoration and abandonment	**888,407**	380,914
Future income taxes *(Note 10)*	**44,945,541**	39,773,845
	200,793,927	120,154,759
Commitments *(Notes 8, 11 and 14)*	**-**	-
Unitholders' equity		
Unitholders' capital/share capital *(Note 5)*	**49,227,530**	19,230,677
Units to be issued *(Note 5)*	**9,013,095**	-
Accumulated earnings	**100,253,217**	51,835,681
Accumulated cash distributions *(Note 6)*	**(40,855,610)**	-
	117,638,232	71,066,358
	414,260,256	242,166,454

See accompanying notes

On behalf of the Board:

Director Director

Peyto Energy Trust

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

For the years ended December 31,

	2003 **$**	2002 $
REVENUE		
Petroleum and natural gas sales, net	**166,934,948**	70,607,767
EXPENSES		
Operating *(Note 7)*	**9,323,597**	4,433,686
General and administrative	**911,503**	1,694,074
Market and reserves based bonus *(Note 8)*	**17,405,380**	-
Future market based bonus provision *(Note 8)*	**12,475,098**	-
Trust reorganization *(Note 9)*	**44,206,442**	-
Interest	**4,738,866**	2,668,964
Depletion, depreciation and site restoration	**23,724,024**	12,223,429
	112,784,910	21,020,153
Earnings before taxes	**54,150,038**	49,587,614
Future income tax expense *(Note 10)*	**5,179,383**	20,626,612
Capital tax expense	**553,119**	406,943
	5,732,502	21,033,555
Earnings for the year	**48,417,536**	28,554,059
Accumulated earnings, beginning of year	**51,835,681**	23,281,622
Accumulated earnings, end of year	**100,253,217**	51,835,681
Earnings per unit/common share *(Note 5)*		
Basic	**1.09**	0.66
Diluted	**1.09**	0.64

See accompanying notes

Peyto Energy Trust

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,

	2003 $	2002 $
Cash provided by (used in)		
OPERATING ACTIVITIES		
Earnings for the period	**48,417,536**	28,554,059
Items not requiring cash:		
Non-cash provision for bonuses	**12,475,098**	1,098,630
Future income tax expense	**5,179,383**	20,626,612
Depletion, depreciation and site restoration	**23,724,024**	12,223,429
Change in non-cash working capital related to operating activities *(Note 12)*	**6,402,059**	1,940,682
	96,198,100	64,443,412
FINANCING ACTIVITIES		
Issue of trust units/common shares, net of costs	**39,002,261**	2,593,389
Distribution payments	**(40,855,610)**	-
Increase in bank debt	**70,000,000**	21,054,528
Change in non-cash working capital related to financing activities *(Note 12)*	**(2,203,827)**	-
	65,942,824	23,647,917
INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(139,423,682)**	(112,550,601)
Change in non-cash working capital related to investing activities *(Note 12)*	**(2,331,582)**	24,663,610
	(141,755,264)	(87,886,991)
Net increase in cash	**20,385,660**	204,338
Cash, beginning of year	**205,558**	1,220
Cash, end of year	**20,591,218**	205,558

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2003 and 2002

1. NATURE OF OPERATIONS

On July 1, 2003 Peyto Exploration & Development Corp. ("Peyto") was reorganized into Peyto Energy Trust (the "Trust"). Shareholders of Peyto received one Trust unit for each common share held. All outstanding common share options were settled for cash prior to the completion of the reorganization. The unitholders of the Trust are entitled to receive cash distributions paid by the Trust and are entitled to one vote for each Trust unit held at unitholder meetings. The Trust units commenced trading on the TSX under the symbol "PEY.UN" on July 4, 2003. The Trust is an unincorporated open-ended limited purpose trust established under the laws of the Province of Alberta. The Trust indirectly owns all the securities of Peyto Exploration & Development Corp. which entitles the Trust to receive all cash flow available for distribution from the business of Peyto after debt service payments, maintenance capital expenditures and other cash requirements. The costs of the reorganization, amounting to $44,206,442, have been expensed (see note 9).

The Trust's principal business activity is the exploration for and development and production of petroleum and natural gas in western Canada.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

While the Trust commenced operations on July 1, 2003, these consolidated financial statements follow the continuity of interest basis of accounting as if the Trust had always existed. This basis is intended to provide unitholders with meaningful and comparative financial information. As a result, the comparative figures are those of Peyto while the results of operations include Peyto's results for the period up to and including June 30, 2003, and the Trust's results of operations from July 1, 2003 to December 31, 2003. Certain comparative figures have been reclassified to conform to the current presentation.

These financial statements include the accounts of Peyto Energy Trust and its wholly owned subsidiaries.

Joint operations

The Trust conducts substantially all of its petroleum and natural gas exploration, development and production activities jointly with others and, accordingly, these consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Property, plant and equipment

(a) Capitalization of costs

The Trust follows the full cost method of accounting for its petroleum and natural gas operations. All costs related to the exploration for and development and production of petroleum and natural gas reserves are capitalized in one Canadian cost center and charged to earnings as set out below. Costs include lease acquisition, geological and geophysical costs and costs of drilling and equipping both productive and non-productive wells. All general and administrative costs are expensed as incurred.

Proceeds from the disposal of properties would usually be applied against capitalized costs, without any gain or loss being realized, unless the disposal results in a change in the depletion rate of greater than 20% in which case a gain or loss on disposal will be recorded.

(b) Depletion and depreciation

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 oil and gas properties for the purpose of calculating depletion. When proved reserves are assigned to the property or it is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion.

Depreciation of gas plants and related facilities is calculated on a straight-line basis over a 20-year term.

Office furniture and equipment are depreciated over their estimated useful lives at declining balance rates between 20% and 30%.

(c) Ceiling test

The Trust calculates a ceiling test whereby the carrying value of its oil and natural gas properties, net of recorded future income taxes and the accumulated provision for future site restoration and abandonment costs, is compared each reporting period-end to an estimate of future net cash flow from the production of gross proved reserves plus the cost of unevaluated land. Net cash flow is estimated using period-end prices and costs and includes future estimated net revenue less production costs, general and administrative expenses, financing costs, site restoration and abandonment costs and income taxes. Should this comparison indicate an excess carrying value, the excess is charged against operations as additional depletion and depreciation. Undeveloped land and seismic costs are tested for impairment each reporting period end based on their estimated market value.

Future site restoration and abandonment costs

Estimated future costs relating to site restoration and abandonment of petroleum and natural gas properties and related facilities are accrued on a unit of production basis over the estimated life of the gross proved reserves. Costs are estimated, net of expected recoveries, based upon current prices, technology and industry standards. The annual provision is accounted for as part of depletion, depreciation and site restoration expense. The accumulated provision is classified as a non-current liability and actual expenditures are charged against the accumulated provision as incurred.

Financial instruments

In certain circumstances, fixed price commodity contracts are used to reduce the Trust's exposure to adverse fluctuations in commodity prices to protect future cash flow used to finance the Trust's capital expenditure program. Gains and losses relating to fixed price contracts that meet hedge criteria are recognized as part of natural gas sales concurrently with the hedged transaction. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified future revenue stream. The Trust believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity, the notional amount and the commodity price basis in the instruments all match the terms of the future revenue stream being hedged.

Realized and unrealized gains or losses associated with the fixed price commodity contracts, which have been terminated or cease to be effective prior to maturity, are deferred as current, or non-current, assets or liabilities on the balance sheet , as appropriate and recognized in earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any realized or unrealized gain or loss on such derivative instrument is recognized in earnings.

Revenue Recognition

Oil and natural gas sales are recognized as revenue when the commodities are delivered to purchasers.

Flow-through Common Shares

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. The estimated tax benefits transferred to shareholders are recorded as future income taxes and a reduction to share capital when the expenditures are incurred and renounced.

Measurement uncertainty

The amount recorded for depletion and depreciation of property, plant and equipment, the provision for site restoration costs and the ceiling test calculation are based on estimates of gross proved reserves, production rates, oil and gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future years could be significant.

Future income taxes

The Trust follows the liability method of tax allocation. Under this method future income tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Market Based Bonus Plan

The Trust measures the compensation cost to employees as the amount by which the quoted market value of the units of the Trust exceed the grant price of the right. Changes, either increases or decreases, in the quoted market value of the Trust units between the date of grant and the measurement date result in a change in the compensation cost. The compensation cost is recognized over the life of the right.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2003 and 2002

3. PROPERTY, PLANT AND EQUIPMENT

	2003 $	2002 $
Property, plant and equipment	**382,315,697**	243,180,014
Office furniture and equipment	**371,500**	284,236
	382,687,197	243,464,250
Accumulated depletion and depreciation	**(44,273,813)**	(21,258,017)
	338,413,384	222,206,233

At December 31, 2003, costs of $25,319,789 (December 31, 2002 - $20,122,240) related to undeveloped land have been excluded from the depletion and depreciation calculation.

For the year ended December 31, 2003, the Trust charged $507,493 (2002 - $178,592) to earnings related to its total future site restoration and abandonment obligation of $10,178,000.

4. LONG-TERM DEBT

The Trust has a syndicated $180 million extendible, 364 day revolving credit facility, followed by a one year non-revolving term-out period. The facility is made up of a $20 million working capital sub-tranche and a $160 million production line. Outstanding amounts on this facility bear interest at rates determined by the Trust's debt to cash flow ratio that range from prime to prime plus 0.75% for debt to cash flow 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. For the year ended December 31, 2003 the combined effective interest rate on amounts outstanding on this facility was 4.7% (December 31, 2002 – 3.6%). Included in 2003 interest expense are commitment and legal fees associated with the facility of $601,000.

Subsequent to December 31, 2003, the credit facility has been increased to $230 million.

5. UNITHOLDERS' CAPITAL/SHARE CAPITAL

Authorized

Unlimited number of voting trust units

Issued and Outstanding

Trust Units/Common Shares (no par value)	Number of Shares/Units	Amount $
Balance, December 31, 2001	41,999,731	16,336,504
Exercise of stock options	1,324,557	2,631,074
Flow-through shares issued	93,900	1,098,630
Tax benefits transferred to shareholders	—	(813,719)
Share issue costs, net of associated tax benefits	—	(21,812)
Balance, December 31, 2002	43,418,188	19,230,677
Share issue costs, net of tax	—	(10,615)
Exercise of stock options	33,334	134,336
Shares converted to trust units ***	(43,451,522)	(19,354,398)
Trust units issued on conversion of shares ***	43,451,522	19,354,398
Trust units issued by private placement	1,943,600	29,873,132
Balance, December 31, 2003	45,395,122	49,227,530

*** Upon completion of the reorganization discussed in note 1, each outstanding common share was converted into one Trust Unit.

In 2002, Peyto, issued 93,900 flow-through shares at a price of $11.70 per share as settlement of its bonus commitment to its employees and consultants. As at December 31, 2002, expenditures in the amount of $1,098,630 had been incurred and the tax deductions related to these proceeds had been renounced to investors

Units to be Issued

On December 31, 2003 the Trust completed a private placement of 330,150 trust units to employees and consultants for proceeds of $9,013,095. The trust units were issued on January 2, 2004.

Stock Options

Prior to the trust conversion, Peyto had a director, employee, and non-employee stock option plan. The number of common shares reserved for issuance at any one time was not to exceed 4,314,262 shares subject to shareholder and regulatory approval. The exercise price of an option was set at the market price of the common shares at the date of grant. Options vested over three years and had terms of 5 years. As part of the plan of arrangement to convert Peyto into a trust, all common share options were cancelled and the optionholders received a cash payment for the intrinsic value of the options (see note 9).

	2003		2002	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Opening	**3,615,333**	**$3.95**	3,310,333	$2.39
Granted	**-**	**-**	1,679,557	$5.52
Exercised	**(33,334)**	**$4.03**	(1,324,557)	$1.99
Cancelled	**(3,581,999)**	**$3.95**	(50,000)	$5.51
Closing	**-**	**-**	3,615,333	$3.95

Stock Based Compensation

Prior to the conversion to an energy trust, Peyto had an employee and director stock option plan where no compensation expense was recognized when the stock options were issued. Had compensation expense for the stock options granted subsequent to January 1, 2002 been determined and expensed, the following pro forma amounts would have resulted.

	2003 **$**	**2002** $
Earnings		
As reported	**48,417,536**	28,554,059
Pro forma	**48,417,536**	27,819,059
Earnings per unit/common share – basic		
As reported	**1.09**	0.66
Pro forma	**1.09**	0.64
Earnings per unit/common share – diluted		
As reported	**1.09**	0.64
Pro forma	**1.09**	0.62

The fair value of common share options granted prior to the trust conversion were estimated to be $735,000 as at the date of grant using the Black-Scholes option pricing model and the following assumptions:

	2003	**2002**
Risk-free interest rate *(%)*	-	3.0
Expected life *(years)*	-	3.0
Expected volatility *(%)*	-	45.0
Expected dividend yield *(%)*	-	0.0

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2003 and 2002

Per Unit/Common Share Amounts

Earnings per unit/common share have been calculated based upon the weighted average number of units or common shares outstanding during the year of 44,430,031 (2002 – 42,978,340). Diluted per unit/common share amounts are calculated using the treasury stock method. The weighted average number of units/common shares used to determine the diluted per unit/share amount in 2003 was 44,430,031 (2002 – 44,494,866).

6. ACCUMULATED CASH DISTRIBUTIONS

During the year, the Trust paid distributions to the unitholders in the amount of $40,855,610 (2002 - $nil) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit
July 2003	July 31, 2003	August 15, 2003	$0.15
August 2003	August 29, 2003	September 15, 2003	$0.15
September 2003	September 30, 2003	October 15, 2003	$0.15
October 2003	October 31, 2003	November 14, 2003	$0.15
November 2003	November 28, 2003	December 15, 2003	$0.15
December 2003	December 31, 2003	January 15, 2004	$0.15

7. OPERATING EXPENSES

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations and the cost of transportation of natural gas. Processing and gathering income related to joint venture and third party gas is included in operating expenses.

	2003 **$**	**2002** $
Field expenses	**9,971,948**	4,680,319
Transmission	**2,818,022**	1,874,546
Processing and gathering income	**(3,466,373)**	(2,121,179)
Total operating costs	**9,323,597**	4,433,686

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2003 and 2002

8. MARKET AND RESERVES BASED BONUS PLAN

The Trust has a bonus plan made up of market and reserve based components.

Under the reserve based component, the bonus pool will be initially comprised of 3% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and distributions, of proved producing reserves calculated using a constant price and a discount rate of 8%.

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 7% of the total number of trust units outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. The bonus is calculated as the number of rights multiplied by the total of the market appreciation and associated distributions of a trust unit for that period. A tax factor is then applied to the result in order to make the bonus plan approximate the previous stock option plan on an after tax basis.

The total cash compensation under these plans for the year ended December 31, 2003 equaled $17,405,380 (2002 - $nil). Compensation cost related to the non-vested rights as at December 31, 2003 was $30,060,476 of which a non-cash provision for future compensation expense of $12,475,098 (2002 - $nil) was recorded in the Statement of Earnings in 2003.

9. PEYTO ENERGY TRUST REORGANIZATION

The following costs were incurred as part of the plan to reorganize Peyto into a trust which was effective July 1, 2003.

	$
Cash payout of stock options	**40,896,442**
Bonuses on cancellation of former Peyto stock option plan	**1,810,000**
Financial advisory, accounting and legal fees, and preparation and printing of the Information Circular	**1,500,000**
	44,206,442

10. FUTURE INCOME TAXES

	2003 **$**	**2002** $
Earnings before income taxes	**54,150,037**	49,587,614
Statutory income tax rate	**40.75%**	42.12%
Expected income taxes	**22,066,140**	20,886,303
Increase (decrease) in income taxes from:		
Non-deductible crown charges	**17,665,105**	9,309,161
Resource allowance	**(12,886,311)**	(8,814,288)
Corporate income tax rate change	**(7,344,113)**	(215,990)
Attributed Canadian Royalty Income (ACRI)	**(1,813,847)**	(430,625)
Trust distributions	**(12,464,270)**	-
Other	**(43,321)**	(107,949)
Future income tax expense	**5,179,383**	20,626,612

The net future income taxes liability comprises:

	2003 **$**	**2002** $
Differences between tax base and reported amounts for depreciable assets	**52,134,293**	41,939,500
Accrued expenditures	**(4,469,380)**	-
Resource allowance & crown lease rentals rate reductions	**-**	(1,247,503)
ACRI carryforwards recognized	**(2,323,754)**	(612,104)
Share and debt issue costs	**(88,051)**	(145,607)
Provision for future site restoration & abandonment	**(307,567)**	(160,441)
	44,945,541	39,773,845

At December 31, 2003 the Trust has tax pools of $189,016,713 (December 31, 2002 - $122,634,772) available for deduction against future income

11. FINANCIAL INSTRUMENTS

Fair Value

The Trust has financial instruments consisting of accounts receivable, amounts due from private placement, deposits, accounts payable, capital taxes payable, cash distributions payable and long-term debt. The carrying value of these instruments approximates fair value unless otherwise stated.

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Trust enters into these contracts, with well established counterparties, for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of natural gas commodity prices. A summary of contracts outstanding in respect of the hedging activities at December 31, 2003 were as follows:

Period Hedged	**Type**	**Daily Volume**	**Floor**	**Ceiling**
Nov. 1, 2003 to March 31, 2004	Costless collar	5,000 GJ	$5.50/GJ	$8.45/GJ
Nov. 1, 2003 to March 31, 2004	Costless collar	5,000 GJ	$7.00/GJ	$9.00/GJ
Nov. 1, 2003 to March 31, 2004	Fixed price	5,000 GJ	$7.49/GJ	
Nov. 1, 2003 to March 31, 2004	Fixed price	5,000 GJ	$7.90/GJ	
Nov. 1, 2003 to March 31, 2004	Fixed price	5,000 GJ	$7.70/GJ	
Nov. 1, 2003 to March 31, 2004	Fixed price	5,000 GJ	$7.47/GJ	
Nov. 1, 2003 to March 31, 2004	Fixed price	5,000 GJ	$6.42/GJ	
Nov. 1, 2003 to March 31, 2004	Fixed price	5,000 GJ	$6.38/GJ	

Based on dealer quotes, had these contracts been closed on December 31, 2003, the Trust would have realized a gain in the amount of $2,868,032.

Subsequent to December 31, 2003 the Trust entered into the following contracts:

Period Hedged	Type	Daily Volume	Floor	Ceiling
April 1 to October 31, 2004	Costless collar	10,000 GJ	$5.00/GJ	$6.50/GJ
April 1 to October 31, 2004	Costless collar	5,000 GJ	$5.00/GJ	$7.10/GJ
April 1 to October 31, 2004	Fixed price	10,000 GJ	$5.64/GJ	
April 1 to October 31, 2004	Fixed price	5,000 GJ	$5.89/GJ	

Credit Risk

A substantial portion of the Trust's accounts receivable is with oil and gas marketing entities. The Trust generally extends unsecured credit to these companies, and therefore, the collection of accounts receivables may be affected by changes in economic or other conditions and may accordingly impact the Trust's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit.

The Trust has not previously experienced any material credit losses on the collection of receivables. Of the Trust's significant individual accounts receivable at December 31, 2003, approximately 75% was owing from one company (December 31, 2002 – 80%).

Interest rate risk

The Corporation is exposed to interest rate risk in relation to interest expense on its revolving committed facility. At December 31, 2003, the increase or decrease in earnings for each 1% change in interest rate paid on outstanding bank balances is approximately $999,000 per annum (December 31, 2002 - $734,000).

12. CHANGES IN NON-CASH WORKING CAPITAL

Changes in non-cash working capital balances are comprised of the following:

	2003 **$**	2002 $
Accounts receivable	**(22,250,168)**	(10,614,137)
Prepaids and deposits	**(4,237,728)**	(368,262)
Due from private placement	**(9,013,095)**	-
Accounts payable and accrued liabilities	**30,648,569**	37,665,129
Capital taxes payable	**(90,196)**	(78,438)
Cash distributions payable	**6,809,268**	-
	1,866,650	26,604,292
Attributable to financing activities	**(2,203,827)**	-
Attributable to investing activities	**(2,331,582)**	24,663,610
Attributable to operating activities	**6,402,059**	1,940,682
Cash interest paid during the year	**4,738,866**	2,668,964
Cash taxes paid during the year	**643,315**	485,381

13. RELATED PARTY TRANSACTIONS

A director of the Trust is a partner of a law firm that was paid $883,049 for legal services for the year ended December 31, 2003 (December 31, 2002 - $54,195). The fees charged were based on standard rates and time spent on Trust matters.

14. COMMITMENTS

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

	$
2004	364,649
2005	364,649
2006	310,626
2007	310,626
	1,350,550

Peyto Exploration & Development Corp. Information

Officers

Don Gray
President and Chief Executive Officer

Roberto Bosdachin
Vice-President, Exploration

Darren Gee
Vice President, Engineering

Scott Robinson
Vice President, Operations

Sandra Brick
Vice President, Finance

Stephen Chetner
Corporate Secretary

Directors

Rick Braund
Don Gray
Brian Craig
Stephen Chetner
John Boyd
Michael MacBean
Ian Mottershead

Auditors
Ernst & Young LLP

Solicitors
Burnet, Duckworth & Palmer LLP

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