PEYTO EXPLORATION & DEVELOPMENT CORP.

Annual Information Form
Fiscal Year Ended December 31, 2002

April 9, 2003

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ABBREVIATIONS

Oil and Liquids		Natural Gas	
bbls	barrels	mcf	thousand cubic feet
mbbls	thousand barrels	mmcf	million cubic feet
mmbbls	million barrels	mcf/d	thousand cubic feet per day
bbls/d	barrels per day	mmcf/d	million cubic feet per day
API	American Petroleum Institute	mmbtu	million British Thermal Units
		bcf	billion cubic feet

Other

boe barrel of oil equivalent of oil and gas on the basis of 1 bbl of oil for 6 mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)

boe/d barrel of oil equivalent per day

ARTC Alberta Royalty Tax Credit

CONVERSION

The following table sets forth certain standard conversions from Standard Imperial units to the International System of Units (or metric units).

To Convert From	To	Multiply By
mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
bbls	Cubic metres	0.159
Cubic metres	bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

THE CORPORATION

Peyto Exploration & Development Corp. ("Peyto" or the "Corporation") was incorporated in the province of Alberta on February 20, 1997 as 728441 Alberta Ltd. and changed its name to Desco Resources Ltd. by Certificate of Amendment dated March 27, 1997. Pursuant to Articles of Amendment dated August 21, 1997, the articles of the Corporation were amended to amend the Corporation's capital and to remove its "private company" provisions and the restrictions on share transfer.

The Corporation held a special meeting of shareholders on October 22, 1998, at which time shareholders approved of the Corporation's major transaction pursuant to the junior capital provisions of the Alberta Securities Commission and CDNX Circular 7. At that time, the shareholders also approved of a change in the name of the Corporation to Peyto Exploration & Development Corp.

Peyto's head office is located at 2900, 450 – 1st Street S.W., Calgary, Alberta T2P 5H1 and the registered office of Peyto is 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9.

DEVELOPMENTS OF THE CORPORATION

General

Peyto is a Calgary, Alberta based energy company engaged in the acquisition, exploration, development and production of oil and natural gas in Western Canada. Peyto's strategy is to enhance shareholder value through the discovery and low cost development of oil and natural gas in the Western Canadian sedimentary basin. Peyto's portfolio of assets includes good quality exploitation and low risk exploration and development opportunities located primarily in the Edson area of Alberta. Management's current philosophy is to fund its growth and ongoing activities from a conservative mix of internally generated cash flow, bank financing and, in certain circumstances, equity financings.

Background of the Corporation

The following is a summary of the business operations of Peyto for the periods shown.

2000

In January 2000, Peyto completed a take-over bid for Largo Petroleum Inc., a non-publicly traded distributing corporation. As a result, Peyto issued 6,603,755 common shares to shareholders of Largo, for a value of $1,981,126.50. At the time the transaction was completed, Largo was producing 95 boe/day.

In the spring of 2000, Peyto purchased P&NG assets from a private corporation in consideration of $3,268,435. The consideration was payable as to $1,123,435 in cash and issuance of 1,650,000 common shares at a price of $1.30 per share. Peyto operated and had ownership in all of these assets before the transaction. These assets were capable of producing 235 boe/day of natural gas and natural gas liquids.

In the spring of 2000, Peyto finished construction of its natural gas processing plant, which was built to handle up to 10 mmcf per day of gas and 600 bbls per day of natural gas liquids. In the fall of 2000, Peyto completed the expansion of its natural gas plant, enabling it to handle an additional 13 mmcf per day of gas and 900 bbls per day of natural gas liquids.

During 2000, Peyto drilled and re-entered 19.4 net natural gas wells which resulted in 12.8 additional natural gas wells on production. Its production exit rate for the year 2000 was 2,358 boe per day. Its capital expenditures during 2000 were $43,586,684.

2001

In the spring of 2001, Peyto expanded the Sundance gas facility to handle 48 mmcf per day of natural gas and 2,000 bbls per day of natural gas liquids. In the fall of 2001, Peyto acquired the remaining partner interest in the Sundance gas plant and associated production of 310 boe/d for a total purchase price of $8,973,321. This strategic acquisition brought Peyto's ownership in the Sundance gas plant to 100%.

During 2001, Peyto drilled and re-entered 24.1 net natural gas wells which resulted in 17.5 additional natural gas wells on production. The exit production rate for the year was 6,508 boe per day. Capital expenditures during 2001 were $79,955,088.

2002

In June 2002, Peyto's Sundance gas plant was expanded to a refrigeration capacity of 100 mmcf/d and raw inlet compression capacity of 74 mmcf/d. In October, 12 mmcf/d of additional compression was added bringing total raw inlet compression capacity at the plant to 86 mmcf/d.

During 2002, Peyto drilled and re-entered 64 gross (55.9 net) natural gas wells. Capital expenditures for 2002 totaled $112,550,601. The exit production rate for 2002 was 11,421 boe per day.

Trends

There are a number of trends in the oil and gas industry that will shape the near future of the business. The first trend is the consolidation phase that the industry has been going through. This has affected companies of all sizes from the small emerging companies to the senior integrated organizations. This trend appears to be accelerating as a number of publicly traded companies are trading below asset or break-up value and as a result it is less expensive for companies to grow by acquiring companies than by focusing entirely on drilling and prospect generation. At a time of high commodity prices and relatively low stock valuations there appears to be a valuation disconnect that has resulted in increased merger and acquisition activity.

The second trend relates to the size of companies that investors are focusing on. The larger market capitalization companies provide for greater liquidity and as result appear to be more attractive, however the smaller companies may present potentially larger returns as they have not yet appreciated in value in relation to the strong commodity prices that the industry is currently experiencing. This may change in the near future as investors look for higher rates of returns, which may encourage them to consider investment in smaller oil and gas companies.

The third trend is the current influence of foreign exploration and production companies on the Canadian oil and gas industry. The main influence has been from American companies that are acquiring companies and assets in Canada in order to build on long-term natural gas supplies to the United States. This trend will continue to influence valuation parameters of Canadian assets and will result in global values for Canadian companies.

A fourth trend is the continuing volatility in the prices for both natural gas and crude oil. Natural gas is a commodity influenced by factors in North America, including, the strength of the economy, weather and demand for electrical generation. Natural gas prices have risen recently with prospects remaining positive for the forthcoming winter. Crude oil is influenced by a world economy and OPEC's ability to adjust supply to world demand. Recent success by OPEC and uncertainty in the Middle East has kept crude oil prices high. High prices provide producers with sufficient cash flow to the extent that the lack of external capital has not been a significant restriction on growth.

The Canadian/U.S. exchange rate also influences commodity prices for Canadian producers as there is a high correlation between Canadian and U.S. oil and natural gas prices. The weakening of the Canadian dollar is a positive trend and with recent significant weakening, the positive effect on pricing is growing in significance.

BUSINESS AND PROPERTIES OF PEYTO

General

Peyto operates in one core area, the Sundance area of Alberta.

Sundance

The Sundance area is located 50 kilometers west of Edson, Alberta, from Township 53–55 and Range 21–22 west of the fifth meridian. Peyto began its operations in this area in the spring of 1999.

Peyto has an average 75% working interest in 59,980 gross (44,985 net) acres of land and operates 99% of its production in the area.

The geology of the area indicates multi-zone potential for liquid-rich natural gas. Peyto currently produces gas from the Belly River, Cardium, Notikewin, Viking and Triassic formations. The majority of Peyto's current production comes from the Cardium formation, which is characterized by low permeability blanket sand.

During 2002, Peyto conducted its most active exploration and development program in this area totaling $106 million in capital expenditures. During 2002, Peyto drilled and re-entered 50.4 net wells in Sundance. Peyto is currently producing 12,000 boe per day of natural gas and natural gas liquids from this area. The Sundance area includes several properties that collectively account for:

95% of 2002 capital expenditures
97% of 2002 production volume
88% of proved and probable reserves at December 31, 2002
37% of undeveloped land holding at December 31, 2002

Peyto plans to spend approximately $110 million of the 2003 capital program in this area. Peyto is planning to drill another 70 wells in the Sundance area over the 2003 calendar year. The majority of these wells are anticipated to be Cardium producers.

The low permeability in the Cardium sand typically limits the drainage area for a well to less than 320 acres. The Alberta Energy and Utilities Board has approved a reduced well spacing of 160 acres per well along the trend and in the Sundance area. This allows Peyto to conduct additional low risk development infill drilling of up to 4 wells per section.

Peyto owns a 100% working interest and operates a gas processing plant located in the Sundance area. The majority of the Corporation's production is processed through this plant, with 128 gross (102.6 net) wells being tied in. Gross natural gas production at the facility is approximately 70 million cubic feet per day, with natural gas liquids production being approximately 3,000 barrels per day.

New Areas

Peyto has also established two new exploration areas with significant land bases and drilling opportunities. Land holdings in these two areas are currently 42,240 gross (32,448 net) acres. Exploration activity is ongoing to determine the potential for future development.

Miscellaneous

The Corporation has a number of minor working interests in non-operated wells throughout Alberta. These properties account for approximately 2% of the Corporation's current production. The corporation does not intend to focus a material amount of time on these properties in 2003.

Operational Data

The following table summarizes key performance measurements in Peyto's core area:

	Production			Undeveloped Land		Drilling
Year	Natural Gas (mmcf/d)	Oil and Liquids (bbls/d)	Combined (boe/d)	Net Acres (000's)	Average Interest (%)	Activity (wells)
Sundance Area						
Annual 2000	6,546	209	1,300	20,926	66%	19.4 net (26 gross)
Annual 2001	20,287	748	4,129	34,753	62%	24.1 net (32 gross)
Annual 2002	41,185	1,761	8,625	32,113	75%	50.4 net (57 gross)

The following table compares various operational data for the periods set out:

	Q4 2002	Q3 2002	Q2 2002	Q1 2002	Q4 2001	Q3 2001	Q2 2001	Q1 2001
Natural Gas Production (mcf per day)	50,556	45,018	38,194	35,049	30,175	22,431	15,502	13,694
Natural Gas Liquids Production (bbls per day)	2,349	2,009	1,512	1,409	1,222	815	621	472
Average product price for Natural Gas ($ per mcf)	5.90	3.49	4.43	4.46	4.32	4.32	7.02	10.30
Average product price for Natural Gas Liquids ($ per bbls)	36.52	33.67	29.95	24.42	23.84	30.48	36.82	39.89
Royalties (% of revenue)	27	25	22	21	17	19	23	27
Operating Expenses ($ per boe)(1)	1.12	1.36	1.67	1.44	1.57	0.93	1.55	1.38
Netbacks ($ per boe)(1)	25.15	16.42	19.72	19.52	19.72	20.83	30.41	41.00
Property Acquisition (in $000's)	762	168	2,215	4,100	9,373	5	135	0
Exploration Activity (in $000's)	14,853	10,220	5,296	6,187	1,678	5,749	7,809	9,657
Development(in $000's)	22,012	13,717	20,759	12,262	10,978	12,717	10,678	11,130

Notes:

(1) Converted on a 6:1 basis
(2) For the periods set forth above, oil production amounted to less than 2% of the Corporation's total oil and gas production and has been included with natural gas liquids on this chart.

Oil and Natural Gas Reserves

The oil and natural gas reserves of the Corporation were evaluated by Paddock Lindstrom & Associates Ltd. with an effective date of December 31, 2002 in a report dated January 27, 2003 (the "Paddock Report"). The following table, based on the Paddock Report, summarizes the oil, liquids and natural gas reserves of the Corporation and the present worth value of estimated future net revenue for these reserves, after provision for the ARTC, using escalated and constant prices and costs as indicated. Salvage and abandonment costs were not considered in the Paddock Report. **All evaluations of future net production revenue set forth in the tables are stated prior to the provision for income taxes, but after overriding and lessor royalties, Crown royalties, freehold minerals tax, direct lifting costs, normal allocated overhead and future investments. It should not be assumed that the discounted future net production revenues estimated by these reserve reports represent the fair market value of the reserves.** Other assumptions and qualifications relating to costs, prices for future production and other matters are included in the Paddock Report. There is no assurance that the future price and cost assumptions used in the Paddock Report will prove accurate and variances could be material.

Escalating Dollar Economics

Reserves Category	Oil		Sales Gas		NGL		Present Value Cash Flow			
	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
	(Mstb)	(Mstb)	(Mmcf)	(Mmcf)	(Mstb)	(Mstb)	(M$)	(M$)	(M$)	(M$)
Proved Producing	33	29	195,918	159,936	8,608	6,088	1,020,216	492,809	400,580	341,290
Proved Non-Producing	0	0	14,965	12,330	571	405	80,290	24,593	19,447	16,333
Proved Undeveloped	0	0	0	0	0	0	0	0	0	0
Total Proved	33	29	210,883	172,266	9,179	6,492	1,100,506	517,402	420,027	357,623
Probable Additional	0	0	195,334	158,682	8,304	5,841	905,514	290,043	207,377	156,390
Total Proved + Probable	33	29	406,216	330,948	17,483	12,333	2,006,020	807,445	627,404	514,013
50% Reduction for Risk	0	0	(97,667)	(79,341)	(4,152)	(2,920)	(452,757)	(145,022)	(103,689)	(78,195)
Risked Proved + Probable	33	29	308,549	251,607	13,331	9,413	1,553,263	662,424	523,716	435,818

Constant Dollar Economics

Reserves Category	Oil		Sales Gas		NGL		Present Value Cash Flow			
	Gross	Net	Gross	Net	Gross	Net	0%	10%	15%	20%
	(Mstb)	(Mstb)	(Mmcf)	(Mmcf)	(Mstb)	(Mstb)	(M$)	(M$)	(M$)	(M$)
Proved Producing	33	29	195,578	161,287	8,584	5,923	1,143,579	574,588	468,202	398,640
Proved Non-Producing	0	0	14,965	12,474	571	396	77,956	29,496	23,581	19,845
Proved Undeveloped	0	0	0	0	0	0	0	0	0	0
Total Proved	33	29	210,543	173,762	9,156	6,319	1,221,535	604,084	491,783	418,485
Probable Additional	0	0	195,258	160,383	8,299	5,700	972,715	363,073	267,161	206,455
Total Proved + Probable	33	29	405,801	334,145	17,454	12,020	2,194,250	967,157	758,944	624,940
50% Reduction for Risk	0	0	(97,629)	(80,192)	(4,149)	(2,850)	(486,358)	(181,537)	(133,581)	(103,228)
Risked Proved + Probable	33	29	308,172	253,953	13,305	9,169	1,707,892	785,621	625,364	521,713

Notes:

(1) Definitions:

"Gross Reserves" means the total of Peyto's working interest share of recoverable reserves under current technology and existing economic conditions before deduction of royalties payable to others in the table based on constant prices. The table based on escalated prices utilizes anticipated economic and operating conditions as set out in Note (2).

"Net Reserves" means the total of Peyto's share of gross reserves less all royalties payable to others.

"Proved Producing" means those reserves that are estimated to be recoverable under the current depletion mechanism and under current operating conditions, from completion intervals open at the time of the estimate in existing wells. These reserves may be currently producing, or if shut-in, they must have been previously on production at commercial rates, and the date of resumption of production must be known with reasonable certainty. These reserves carry a high level of confidence that the predicted levels of recovery forecast will be met or exceeded.

"Proved Non-Producing" means those reserves that are not currently producing either due to lack of facilities and/or markets. These reserves carry a high level of confidence that the predicted levels of recovery forecast will be met or exceeded.

"Proved Undeveloped" these are proved reserves which are expected to be recovered from new wells on undrilled acreage, or from existing wells where relatively major expenditures are required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. In any event, there must be a reasonable certainty that the development will proceed within the time frame assumed. These reserves carry a high level of confidence that the predicted levels or recovery from the level of capital expenditure forecast will be met or exceeded. By the nature of the reserves in question, the level of risk of timing and recovery factor is greater than in the Proved Producing case.

"Probable" means those reserves that are not proven but are potentially recoverable from undeveloped land or untested zones behind casing where the potential has been evaluated by geological/geophysical and/or engineering data but where an appreciable capital expenditure is required to prove the economic viability of those reserves. Probable reserves to be obtained by the application of enhanced recovery processes will be the incremental recovery above the proven reserves. These additional reserves are those which can be reasonably estimated to be recoverable upon application of the enhanced recovery scheme. The classification of Probable reserves as opposed to Proved reserves, may be due to: geological technical economic operational ownership or other risks. Overall there should be a reasonable expectation of the ultimate recovery at a minimum of the reserves estimated based on the predicted capital expended, but the timing of such recovery is likely to be uncertain. **PROBABLE RESERVES HAVE BEEN REDUCED BY 50% TO REFLECT THE RISKS ASSOCIATED WITH RECOVERY.**

"Royalties" means royalties paid to others. The royalties deducted from the reserves are based on the percentage royalties calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling price, the price forecasts for the individual properties in question have been employed.

(2) Average yearly general product prices in the escalated price case in the Report, adjusted for the quality of the crude, are outlined in the following table:

Crude Oil & Natural Gas Price Forecast
As of January 1, 2003

	Crude Oil		Natural Gas and Natural Gas Liquids at Plant Gate				
Year	WTI Cushing Oklahoma $US/bbl	Edmonton Par Price 40 API $/bbl	Gas Price Alberta $/MMBtu	Ethane $/bbl	Propane $/bbl	Butane $/bbl	Condensate $/bbl
2003	26.00	38.96	5.60	17.07	25.32	23.38	38.96
2004	24.00	35.86	5.20	15.95	23.31	21.52	35.86
2005	22.50	33.53	4.88	15.08	21.80	20.12	33.53
2006	22.95	34.20	4.94	15.46	22.23	20.52	34.20
2007	23.41	34.89	5.00	15.65	22.68	20.93	34.89
2008	23.88	35.59	5.06	15.83	23.13	21.35	35.59
2009	24.35	36.30	5.12	16.01	23.59	21.78	36.30
2010	24.84	37.02	5.18	16.19	24.07	22.21	37.02
2011	25.34	37.76	5.24	16.37	24.55	22.66	37.76
2012	25.85	38.52	5.30	16.55	25.04	23.11	38.52
2013	26.36	39.29	5.36	16.72	25.54	23.57	39.29
2014	26.89	40.08	5.41	16.90	26.05	24.05	40.08
2015	27.43	40.88	5.47	17.07	26.57	24.53	40.88
2016	27.98	41.69	5.53	17.24	27.10	25.02	41.69
2017	28.54	42.53	5.63	17.56	27.64	25.52	42.53
2018	29.11	43.38	5.74	17.91	28.20	26.03	43.38
2019	29.69	44.25	5.86	18.27	28.76	26.55	44.25
2020	30.28	45.13	5.98	18.64	29.34	27.08	45.13

The revenue forecast presented in the Paddock Report are based on escalating and constant dollar economics. In the escalated dollar case, the price forecast for the reference price of oil at Cushing and Edmonton, as well as the netback prices for gas for the major purchasers are detailed above. For the constant dollar case, oil and gas prices used in generating the revenue forecasts are based on October, November and December average 2002 prices received and have been held constant for the forecast period. All oil prices used in the evaluation have been adjusted from the reference price for quality and transportation; gas prices have been adjusted for heating value. Please note that the effects of any oil and gas hedging activities by the Company have not been included in the report.

Future operating and capital costs were inflated at 2% per year throughout the forecast period, for the escalated case. The inflation rate was removed to run constant dollar summaries.

(3) Field production data up to and including December 31, 2002 was used in order to classify and evaluate the proven producing reserves in the Paddock Report. Accordingly, as at December 31, 2002, the percentage of proven producing reserves on production was 100%.

Reserve Reconciliation

	Natural Gas (Mmcf)			Oil and Liquids (Mstb)			Oil (Mstb)			NGL's (Mstb)		
	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total	Proved	Probable	Total
Opening Balance 01-12-31	125,142	143,459	268,601	6,320	6,882	13,202	44	-	44	6,276	6,882	13,158
Net Additions	101,164	51,875	153,039	3,557	1,422	4,979	-	-	-	3,557	1,422	4,979
Technical Revisions	-	-	-	-	-	-	-	-	-	-	-	-
Production	15,423	-	15,423	665	-	665	11	-	11	654	-	654
Closing Balance 02-12-31	210,883	195,334	406,217	9,212	8,304	17,516	33	-	33	9,179	8,304	17,483

Drilling History

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the periods indicated:

	12 Months Ended December 31,					
	2002		2001		2000	
	Gross(1)	Net(1)	Gross(1)	Net(1)	Gross(1)	Net(1)
Oil wells	-	-	-	-	-	-
Natural gas wells	64	55.9	32	24.1	29	21.3
Service wells(2)	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	64	55.9	32	24.1	29	21.3

Notes:

(1) **"Gross"** wells are the total number of wells in which the Corporation has an interest. **"Net"** wells are the aggregate of the number obtained by multiplying each gross well by the Corporation's percentage working interest therein.
(2) **"Service"** wells are those used for water disposal, water injection or water source.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which the Corporation has a working or a royalty interest which are producing or which the Corporation considers to be capable of production as at December 31, 2002:

	Producing Wells				Shut-in Wells(1)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)
Alberta	49	3.9	160	120.0	-	-	15	8.3
Saskatchewan	-	-	-	-	-	-	-	-
British Columbia	-	-	3	0.2	-	-	2	0.1
Total	49	3.9	163	120.2	-	-	17	8.4

Notes:

(1) **"Shut-in"** wells means wells which have encountered and are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons. Shut-in wells in which the Corporation has an interest are located no further than 10 kilometres from gathering systems, pipelines or other means of transportation.
(2) **"Gross"** wells are the total number of wells in which the Corporation has an interest.
(3) **"Net"** wells are the aggregate of the numbers obtained by multiplying each gross well by the Corporation's percentage working interest therein.

Capital Expenditures

The following table summarizes exploration and development capital expenditures for the periods indicated excluding property acquisitions, administrative assets and flow through tax adjustments.

	Years Ended December 31,		
	2002	2001	2000
Land, lease and seismic	5,065,000	5,090,000	2,024,500
Drilling and completion	76,350,000	48,664,000	19,177,215
Production, equipment, facilities and pipelines	24,101,000	16,642,000	12,146,987
Capitalized general and administrative	-	-	-
Total	105,516,000	70,396,000	33,348,702

SELECTED FINANCIAL INFORMATION

Annual Data

The following table sets forth certain financial information of the Corporation for the years 2000 to 2002:

		Years Ended December 31,		
		2002	2001	2000(1)
Gross revenue		$ 92,709,000	$ 52,247,000	$ 19,954,000
Cash flow		62,503,000	36,326,000	12,458,000
Per share	- basic	1.45	0.87	0.37
	- diluted	1.41	0.86	0.36
Net income		28,554,000	17,524,000	5,906,000
Per share	- basic	0.66	0.42	0.18
	- diluted	0.64	0.41	0.17
Total assets		242,166,454	130,473,953	60,057,098
Revolving demand loan		80,000,000	58,945,472	13,199,728

There were no extraordinary items recorded in the above reporting periods.

Note:

(1) The financial statements for 2000 were accounted for on a consolidated basis to include Peyto's subsidiary Largo Petroleum Inc. Peyto and Largo Petroleum Inc. were amalgamated effective December 31, 2000.

Quarterly Data

The following table sets forth certain financial information of the Corporation for the following periods:

	2002				2001			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Gross revenue	$35,354,000	$20,676,000	$19,530,000	$17,150,000	$14,679,000	$11,195,000	$11,987,000	$14,386,000
Cash flow	23,746,000	13,474,000	13,185,000	12,098,000	10,370,000	8,115,000	8,160,000	9,681,000
Per share - basic	0.55	0.31	0.31	0.29	0.25	0.19	0.20	0.24
- diluted	0.52	0.30	0.30	0.28	0.24	0.19	0.19	0.23
Net income (loss)	10,310,000	5,957,000	6,362,000	5,925,000	4,969,000	3,486,000	4,450,000	4,618,000
Per share - basic	0.24	0.14	0.15	0.14	0.12	0.08	0.11	0.11
- diluted	0.23	0.13	0.14	0.14	0.12	0.08	0.10	0.11

DIVIDEND RECORD AND POLICY

Since its incorporation, Peyto has not paid any cash dividends on the Common Shares. Dividends on the Common Shares will be paid solely at the discretion of the board of directors after taking into consideration the financial condition of Peyto and the economic environment in which it is operating. No dividends are expected to be paid in the immediate or foreseeable future.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is a summary of the variation in Peyto's operating results for the periods indicated.

Twelve Months Ended December 31, 2002 Compared to Twelve Months Ended December 31, 2001

Gross revenues totaled $92.7 million for the year 2002, an increase of 77 percent from $52.2 million in 2001. This increase is a result of higher production volumes despite lower natural gas prices. The price of natural gas averaged $4.63 per mcf for the year 2002 down 20 percent from $5.81 per mcf in 2001. Oil and natural gas liquids prices averaged $32.06 per barrel in 2002 up 5 percent from $30.52 per barrel in 2001.

A successful drilling program resulted in natural gas production for the year increasing by 106 percent to 42.2 mmcf per day in 2002 from 20.5 mmcf per day in 2001. Oil and natural gas liquids production increased by 132 percent to 1,823 barrels per day in 2002 from 785 barrels per day in 2001. Production for the year averaged 8,865 barrels of oil equivalent ("boe", natural gas converted on a 6:1 basis) per day, an increase of 111 percent from 4,201 boe per day for 2001.

2002 royalties, net of Alberta Royalty Tax Credit (ARTC), increased by 100 percent to $22.1 million from $11.1 million in 2001 due to higher gross revenues associated with increased production volumes. The 2002 average royalty rate was 24 percent compared to 22 percent for 2001.

Increased production volumes caused operating costs to rise to $4.4 million in 2002 from $2.1 million in 2001. On a barrel of oil equivalent basis, operating costs were $1.37 per boe in 2002 compared to $1.36 per boe in 2001. 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 $1.45, transportation $0.58 and processing and gathering income a recovery of $0.66.

General and administrative expenses increased by 7 percent to $1,694,000 for 2002 from $1,589,000 in 2001. The Corporation does not capitalize general and administrative expenses. Operator overhead recoveries related to capital expenditures and well operations totaling $1.7 million have been netted from 2002 general and administrative expenses. On a boe basis, general and administrative expenses decreased by 50 percent to $0.52 per boe in 2002 from $1.04 per boe in 2001. This reduction was the result of the increase in production volumes while maintaining a similar level of staff. Fourth quarter G&A expenses included bonuses to employees and consultants totaling $1,047,500. The bonuses are awarded based on incremental cash flow per share achieved by the Corporation. Recipients were given the option to receive their bonus in the form of cash or flow-through shares of the Corporation at a price of $11.70 per share (25% premium to 10 day weighted average price) with 98 percent choosing to increase their stake in the Corporation by selecting the share option.

Financing charges for 2002 were $2.7 million up from $1.8 million in 2001. The increase was the result of higher debt levels associated with Peyto's 2002 capital expenditure program which totaled $112.6 million compared with $79.9 million in 2001.

Depreciation, depletion and site restoration expenses were $12.2 million for 2002 compared to $6.5 million for 2001 as a direct result of Peyto's increased asset base and production volumes. On a per boe basis, the average depreciation, depletion and site restoration rate decreased to $3.78 in 2002 from $4.22 in 2001.

The provision for future income tax increased to $20.6 million in 2002 from $11.5 million in 2001. The increase in the tax provision in 2002 is a direct result of Peyto's increased profitability due to significantly higher production volumes.

The 111% increase in production volumes caused funds from operations for 2002 to increase to $62.5 million compared with $36.3 million in 2001. Lower average natural gas prices caused Peyto's field netback for the period to decrease from $25.50 per boe in 2001 to $20.45 per boe in 2002. Earnings for 2002 were $28.6 million or $0.66 per share compared with $17.5 million in 2001 or $0.42 per share.

Twelve Months Ended December 31, 2001 Compared to Twelve Months Ended December 31, 2000

Gross revenues totaled $52.2 million for the year 2001, an increase of 162 percent from $19.9 million in 2000. This increase is a result of higher production volumes despite lower commodity prices. The price of natural gas averaged $5.81 per mcf for the year 2001 down 11 percent from $6.56 per mcf in 2000. Oil and natural gas liquids prices averaged $30.52 per barrel in 2001 down 24 percent from $39.92 per barrel in 2000.

Natural gas production for the year increased by 201 percent to 20.5 mmcf per day from 6.8 mmcf per day in 2000. Oil and natural gas liquids production increased by 217 percent to 785 bbl/d in 2001 from 248 bbl/d in 2000. Production for the year averaged 4,202 barrels of oil equivalent ("boe", natural gas converted on a 6:1 basis) per day up 204 percent from 1,381 boe per day for 2000.

2001 royalties, net of Alberta Royalty Tax Credit (ARTC), increased by 140 percent to $11.1 million from $4.6 million in 2000 due to higher gross revenues associated with increased production volumes. The 2001 average royalty rate, before ARTC, was 22 percent compared to 26 percent for 2000.

Due to increased production volumes, operating costs rose to $2.1 million in 2001 from $1.3 million in 2000. On a barrel of oil equivalent basis, operating costs declined by 47 percent to $1.36 per boe in 2001 from $2.58 per boe in 2000. 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 $1.26, transportation $0.75 and processing and gathering income a recovery of $0.65.

General and administrative expenses increased by 70 percent to $1,589,000 for 2001 from $932,000 in 2000. The Corporation does not capitalize general and administrative expenses. Operator overhead recoveries related to capital expenditures and well operations totaling $1.2 million have been netted from 2001 general and administrative expenses. On a boe basis, general and administrative expenses decreased by 44 percent to $1.04 per boe in 2001 from $1.85 per boe in 2000. This reduction was the result of the increase in production volumes while maintaining a similar level of staff. Fourth quarter G&A expenses included bonuses to employees and consultants totaling $873,500. The bonuses are awarded based on incremental cash flow per share achieved by the Corporation. Recipients were given the option to receive their bonus in the form of cash or flow-through shares of the Corporation at a price of $4.50 per share (25% premium to 10 day weighted average price) with 82 percent choosing to increase their stake in the Corporation by selecting the share option.

Financing charges for 2001 were $1.8 million up from $605,000 in 2000. The increase was due to higher debt levels associated with Peyto's 2001 capital expenditures totaling $79.9 million compared with $43.6 in 2000.

Depreciation, depletion and site restoration expenses were $6.5 million for 2001 compared to $1.9 million for 2000 as a direct result of Peyto's increased asset base and production volumes. On a per boe basis, the average depreciation, depletion and site restoration rate increased to $4.22 in 2001 from $3.77 in 2000.

The provision for future income tax increased to $11.5 million in 2001 from $4.7 million in 2000. The increase in the tax provision in 2001 is a direct result of Peyto's increased profitability due to significantly higher production volumes.

Funds from operations for 2001 were $36.3 million compared with $12.5 million in 2000. This 190 percent increase was the result of increased production volumes and lower operating costs on a per boe basis. On a per share basis, 2001 resulted in funds from operations of $0.87 per share versus $0.37 per share in 2000. Due to lower average commodity prices, Peyto's field netback for the period decreased from $27.82 per boe in 2000 to $25.50 per boe in 2001. Earnings for 2001 were $17.5 million or $0.42 per share compared with $5.9 million in 2000 or $0.18 per share.

Liquidity and Capital Resources

For the year ended December 31, 2002, the Corporation incurred net capital expenditures of $112.6 million. Capital expenditures during 2002 were comprised of $78.1 million for exploration and development, $24.1 million for facilities, gathering systems and equipment and $10.4 million for acquisitions and land. At December 31, 2002, the Corporation had a working capital deficiency, including the revolving demand loan, of $110.9 million, resulting in a net debt to running cash flow ratio of 1.2:1 based on annualized fourth quarter cash flow.

Capital expenditures for 2002 and 2001 were funded primarily by cash flow and bank debt, with equity issues limited to the exercise of stock options and the issuance of flow through shares pursuant to the Corporation's employee bonus plan.

Outlook

Peyto's 2003 capital expenditure program is budgeted to be between $110 million and $160 million and will be financed from available bank lines and the cash flow expected to be generated in 2003. In 2003, 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 $105 million revolving demand loan facility that bears interest at prime and does not require any principal repayments in 2003. The Corporation settles sales receivables and trade payables in accordance with normal industry practices. Working capital liquidity is maintained through drawing and repaying the bank facilities.

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 Corporation 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 proven 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 2002 oil prices strengthened but continued to be volatile. Peyto believes that oil prices will continue to be volatile in 2003. Natural gas prices have become increasingly favourable in recent months. Given this outlook, Peyto believes that capital investment and competition for land, acquisitions and services will increase in 2003. Peyto anticipates relative stability with respect to exchange and interest rates, although Peyto has a low sensitivity to these matters.

Recent Pronouncement

The CICA issued Accounting Guideline 13 "Hedging Relationships" which deals with the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting. The guideline establishes conditions for applying hedge accounting, but does not specify hedge accounting methods. The guideline is effective for fiscal years beginning on or after July 1, 2003. The Corporation anticipates that adoption of Accounting Guideline 13 will not have a material effect on its consolidated financial statements.

MARKET FOR SECURITIES

The Common Shares began trading on the Toronto Stock Exchange on May 28, 2001 and prior thereto traded on the Canadian Venture Exchange. The following table sets out the high and low price for board lot trades and the volume of trading of the Common Shares as reported by such exchange for the periods.

Price Range and Trading Volume of Common Shares on the Toronto Stock Exchange

	Price Range			
	High	Low	Close	Trading Volume
2000				
First Quarter	$ 0.96	$ 0.63	$ 0.96	2,413,900
Second Quarter	$ 1.89	$ 0.75	$ 1.60	4,864,400
Third Quarter	$ 2.02	$ 1.36	$ 1.90	3,102,100
Fourth Quarter	$ 2.42	$ 1.68	$ 2.42	2,501,021
2001				
First Quarter	$ 3.33	$ 2.08	$ 3.25	5,276,300
Second Quarter	$ 4.20	$ 2.64	$ 3.15	6,823,000
Third Quarter	$ 3.30	$ 1.91	$ 2.27	2,664,800
Fourth Quarter	$ 4.30	$ 2.20	$ 3.97	3,685,400
2002				
First Quarter	$ 5.92	$ 3.80	$ 5.85	24,559,289
Second Quarter	$ 8.17	$ 5.05	$ 6.90	17,571,461
Third Quarter	$ 8.75	$ 5.32	$ 8.30	13,125,421
Fourth Quarter	$ 11.33	$ 8.01	$ 11.15	88,902,805
2003				
January	$ 13.00	$ 10.15	$ 12.70	4,658,969
February	$ 14.35	$ 12.55	$ 14.25	3,081,100
March	$ 14.30	$ 11.25	$ 13.15	3,508,849
April (1-8)	$ 13.15	$ 11.60	$ 13.00	1,004,805

DIRECTORS AND OFFICERS

The following table sets forth the names, municipality of residence, principal occupation and year of becoming a director or officer.

Name and Municipality of Residence	Office Held	Date of Appointment	Principal Occupation
Rick Braund (3) Calgary, Alberta	Chairman of the Board	October, 1998	Chairman of Buck Oil Ltd., a private oil and gas company
Donald Gray (3) Calgary, Alberta	President, Chief Executive Officer and Director	October, 1998	President and Chief Executive Officer of the Corporation
Brian Craig (1) (2) (3) Calgary, Alberta	Director	October, 1998	President and Chief Executive Officer of Solium Capital Inc.
Mike Broadfoot (1) (2) (3) Calgary, Alberta	Director	October, 1998	Corporate Director and Private Investor
Stephen J. Chetner (1) (3) Calgary, Alberta	Secretary and Director	December, 2000	Corporate lawyer at Burnet, Duckworth & Palmer LLP
Roberto Bosdachin Calgary, Alberta	Vice-President, Exploration	April, 2000	Vice-President, Exploration of the Corporation
Darren Gee Calgary, Alberta	Vice-President, Engineering	March, 2001	Vice-President, Engineering of the Corporation
Lyle Skaien Calgary, Alberta	Vice-President, Operations	July, 2001	Vice-President, Operations of the Corporation
Sandra Brick Calgary, Alberta	Vice-President, Finance	May, 2001	Vice-President, Finance of the Corporation
John Boyd (1) (2) (3) Hillarys, W. Australia	Director	July, 2002	Private Investor

Notes:

(1) Member of Audit Committee.
(2) Member of Compensation Committee.
(3) Member of Reserves Committee.

As of the date hereof, the members of the board of directors and executive officers of the Corporation, as a group, beneficially own, directly or indirectly 9,126,771 Common Shares (21%).

All of the directors and senior officers have been engaged for more than 5 years in their present principal occupations or executive positions with the same or associated corporations, except as follows:

- Mr. Rick Braund was President of Viewpoint Resources Ltd., a private oil and gas company engaged in the exploration, development and production of oil and natural gas from October 1994 to 1999 at which time he then became Chairman of Buck Oil Ltd.

- Mr. Don Gray was a Senior Exploitation Engineer with Pinnacle Resources Ltd., a publicly traded oil and gas company, from August 1997 until July 1998.

- Mr. Brian Craig was President and Chief Executive Officer of Stormworks Inc. from January 2000 to May 2002. Mr. Craig was the President of Radiant Energy, a private consulting firm from January 1998 to January 2000. From May to December 1997, Mr. Craig was the President of Quadrus Development Inc., a private software consulting firm.

- Mr. Mike Broadfoot was President and Chief Executive Officer of Engage Energy Inc. (the energy trading and marketing subsidiary of Westcoast Energy Inc.) from 2000 to 2002, at which time Westcoast Energy Inc. was sold to Duke Energy Inc. Prior thereto, from 1989 to 2000, Mr. Broadfoot held various executive and management positions with Engage Energy Inc. and its predecessor corporations.

- Mr. Roberto Bosdachin was a Senior Staff Geologist with Calahoo Petroleum from October 1998 to April 2000. Prior thereto, he was an Exploration Geologist with Cimarron Petroleum from November 1996 to June 1997.

- Mr. Darren Gee was a Manager of Exploitation Engineering for Husky Energy's Northwest Plains Business Unit from August 2000 to April 2001. Prior thereto, Mr. Gee was the Chief Exploitation Engineer with Renaissance Energy Ltd. from 1997 until its take over by Husky in August 2000.

- Mr. Lyle Skaien was an Asset Manager with Husky Energy from August 2000 to July 2001. From 1998 to August 2000 he was a Chief Production Engineer with Renaissance Energy Ltd. Prior thereto, Mr. Skaien was a Production Manager with Renaissance Energy Ltd. from 1994 to 1998.

The term of office of all of the above directors expires at the next annual meeting of shareholders of Peyto or until their successors are appointed, subject to the provisions of the *Business Corporations Act* (Alberta) and the by-laws of Peyto.

Circumstances may arise where members of the board of directors of Peyto are directors or officers of corporations which are in competition to the interests of Peyto. No assurances can be given that opportunities identified by such board members will be provided to Peyto. Pursuant to the *Business Corporations Act* (Alberta), directors who have an interest in a proposed transaction upon which the board of directors is voting are required to disclose their interests and refrain from voting on the transaction.

The information as to principal occupation and as to shares beneficially owned directly or indirectly or over which control or direction is exercised is based upon information provided by the nominees, officers or directors. Each of the above nominees is a Director of the Corporation elected at the last annual general meeting of shareholders of the Corporation, other than John Boyd who was appointed after the last annual meeting.

HUMAN RESOURCES

As at December 31, 2002, Peyto employed 9 full-time head office employees. Contract operators are retained for all field operations.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry. All current legislation is a matter of public record and Peyto is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing - Oil

In Canada, oil producers negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the overall supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light oil, and not exceeding two years in the case of heavy oil, provided that an order approving any such export has been obtained from the National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas sold is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the government of Canada. As is the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB licence and Governor in Council approval.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the US and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-US Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the US or Mexico will be allowed provided that the restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade then only if the export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

The NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quantity of the petroleum product produced.

From time to time the governments of Canada and Alberta have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced production projects.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil royalty rates vary from province to province. In Alberta where Peyto has the majority of its properties and production, oil royalty rates vary between 10% and 35% for oil and 10% and 30% for new oil. New oil is applicable to oil pools discovered after March 31, 1974 and prior to October 1, 1992.

Effective January 1, 1994, the calculation and payment of natural gas royalties became subject to a simplified process. The royalty reserved to the Crown, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the ARTC program. The ARTC program is based on a price-sensitive formula, and the ARTC rate currently varies between 75% for prices for oil at or below $100 per cubic metre and 25% for prices above $210 per cubic metre. The ARTC rate is currently applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid to the provincial governments. These incentives increase the net income of Peyto.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders. Environmental legislation in Alberta has undergone a major revision and has been consolidated into the *Environmental Protection and Enhancement Act*. Under the new Act, environmental standards and compliance for releases, clean-up and reporting are stricter and more onerous. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have an incremental effect on the cost of conducting operations in Alberta. This legislation rolled the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental and review process.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal holders of the Corporation's securities, options to purchase securities and interest of insiders in material transactions, where applicable, is contained in the Corporation's Information Circular - Proxy Statement prepared in respect of the Annual and Special Meeting of Shareholders held on June 6, 2002. Additional financial information is contained in the Corporation's consolidated comparative financial statements for the year ended December 31, 2002, which information is incorporated by reference herein.

Copies of the Information Circular - Proxy Statement, the financial statements, including any interim financial statements, additional copies of this Annual Information Form, and if the Corporation is in the course of a distribution pursuant to a short-form prospectus or a preliminary short-form prospectus, any other documents incorporated therein by reference may be obtained upon request from the Vice President, Finance of the Corporation at the head office of Peyto, 2900, 450 – 1st Street S.W., Calgary, Alberta T2P 5H1. Telephone: (403) 261-6902; Facsimile: (403) 261-8976.