Paramount Resources Ltd.

Paramount Resources Ltd. Financial And Operating Results For The Year Ended December 31, 2002

FOR: PARAMOUNT RESOURCES LTD.

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Paramount Resources Ltd. Financial And Operating Results
For The Year Ended December 31, 2002

CALGARY, ALBERTA--Paramount Resources Ltd. ("Paramount") is pleased to announce its financial and operating results for the year ended December 31, 2002.

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PARAMOUNT RESOURCES LTD
Highlights

FINANCIAL ($ thousands except per share amounts)	Three Months Ended December 31 2002	2001	% Change	Year Ended December 31 2002	2001	% Change
Gross Revenue	138,337	87,670	58%	473,942	528,373	-10%
Cash Flow						
From operations	62,102	47,732	30%	259,916	303,937	-14%
Per share -basic	1.04	0.80	30%	4.37	5.11	-14%
-diluted	1.04	0.80	30%	4.36	5.11	-15%
Earnings (loss)						
Net earnings (loss)	(41,399)	(10,433)	297%	10,307	118,902	-91%
Per share -basic	(0.70)	(0.18)	289%	0.17	2.00	-92%
-diluted	(0.70)	(0.18)	289%	0.16	2.00	-92%
Capital Expenditures						
Exploration and development	14,047	46,930	-70%	217,196	272,323	-20%
Summit acquisition	11,715	-	-	449,648	-	-
Other	(108,400)	12,185	-990%	(145,580)	(11,139)	1207%
Net capital expenditures	(82,638)	59,115	-240%	521,264	261,184	100%
Total Assets	1,536,384	1,176,323	31%	1,536,384	1,176,323	31%
Net Debt	555,243	290,698	91%	555,243	290,698	91%
Shareholders' Equity	546,105	535,384	2%	546,105	535,384	2%
Weighted Average Common Shares Outstanding	59,459	59,453		59,458	59,453	
Common shares outstanding at Year-end (000's)	59,459	59,453	0%	59,459	59,453	0%
Common shares outstanding at February 28, 2003 (000's)	60,169			60,169		

OPERATING

Production						
Natural gas (MMcf/d)	262.6	218.2	20%	241.4	225.0	7%
Crude oil and liquids (Bbl/d)	8,552	2,002	327%	5,663	2,165	162%
Total Production (MMcfeq/d)@ 10:1	348.2	238.4	46%	298.0	246.7	21%
Total Production (BOE/d) @ 6:1	52,326	38,365	36%	45,898	39,665	16%
Average Prices						
Natural gas (pre-hedge)($/Mcf)	4.54	3.03	50%	3.53	5.93	-40%
Natural gas ($/Mcf)	4.60	4.17	10%	4.08	6.12	-33%
Crude oil and liquids ($/Bbl)	35.27	27.81	27%	34.64	35.48	-2%
Reserves (proved and probable)						
Natural gas (Bcf)						
Proven	446.5	437.7	2%			
Proven and probable	618.6	563.7	10%			
Crude Oil and liquids (MBbl)						
Proven	17,545	6,339	177%			
Proven and probable	22,845	7,967	187%			
Estimated present worth value before tax discounted @ 10%						
Proven ($mm)	983	696	41%			
Proven and probable ($mm)	1,258	870	45%			
Drilling Activity (gross)						
Gas	10	31	-68%	114	167	-32%
Oil	4	4	-	9	12	-
Other	(1)	-	-	1	1	-
D&A	2	(1)	-	11	16	-31%
Total wells	15	34	-56%	135	196	-31%
Success rate	87%	100%	-13%	92%	92%	0%

(1) Throughout this report, unless otherwise stated, crude oil and liquids volumes have been converted to natural gas (Mcfeq) on the basis that one barrel of oil equals 10 Mcf of gas

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SIGNIFICANT EVENTS

- Acquisition of Summit Resources Limited

On June 28, 2002, Paramount closed the acquisition of Summit Resources Limited ("Summit") for cash consideration of $251.4 million and assumed net debt of $87.0 million. The acquisition diversified the Company's production base and consolidated certain working interests in Central Alberta which the Company believes to be highly prospective.

- Creation of an Independent Energy Trust

In conjunction with Paramount's acquisition of Summit, the Company announced its intention to create an independent Energy Trust (the "Trust"), providing shareholders an investment which would complement Paramount's traditional exploration and development strategy.

During the first quarter 2003, all necessary regulatory clearances with respect to the Canadian prospectus and the U.S. Registration Statement were received. Paramount subsequently transferred a portion of its Northeast Alberta assets to the Trust and issued a $51 million dividend in kind of Trust Units received from the Trust to its shareholders. On March 11, 2003, the Trust closed a rights offering, the proceeds of which partially capitalized the Trust and allowed it to purchase from Paramount additional assets in Northeast Alberta.

- Settlement of Bitumen/Natural Gas Co-Production Issue

On June 27, 2002, Paramount received compensation of $47.1 million in settlement for the Surmont shut-in order of May 1, 2000.

- Sale of Remaining Investment in Peyto Exploration and Development Corp.

Paramount monetized its remaining investment in Peyto Exploration and Development Corp. to realize cash proceeds of $45.0 million in 2002 for a net gain of $40.1 million.

FINANCIALS

The financial and operating results at December 31, 2002 reflect the acquisition of Summit Resources Limited effective June 28, 2002.

Petroleum and natural gas revenue totaled $473.9 million for the year ended December 31, 2002, as compared to $528.4 million reported for the corresponding period in 2001. Included in petroleum and natural gas sales are $46.8 million of commodity hedging gains attributable to petroleum and natural gas hedges in place during 2002.

For the three months ended December 31, 2002, petroleum and natural gas revenue totaled $138.3 million, up 58 percent from $87.7 million for the same period in 2001. Compared to the third quarter, quarterly revenue increased 19 percent from $116.5 million; a direct result of increased commodity prices. The fourth quarter hedging gain totaled $0.9 million.

Cash flow from operations totaled $259.9 million or $4.37 per common share, representing a 14 percent decrease from the $303.9 million, or $5.11 per common share, reported for 2001. Cash flow during the fourth quarter amounted to $62.1 million or $1.04 per common share, 30 percent higher than the $47.7 million or $0.80 per common share reported for the same period in 2001.

Net income for the year ended December 31, 2002, decreased 91 percent to $10.3 million or $0.17 per common share compared to $118.9 million or $2.00 per common share reported for the same period a year earlier. Net income includes a fourth quarter loss of $41.4 million or $0.70 per common share as compared to a loss of $10.4 million or $0.18 per common share in 2001. Extraordinary to earnings in 2002 was a charge of $66 million for exploratory dry hole costs associated with petroleum and natural gas assets in California and Wyoming; $49.4 million of negative revisions to the book value of undeveloped unproved exploratory leases which the Company has determined will not be developed and a $31.2 million write-down resulting from the impairment of certain producing non-core oil and natural gas assets.

OPERATIONS

Daily production increased 16 percent during 2002 to 45,898 BOE/D on a 6:1 basis as compared to average production of 39,665 BOE/D in 2001. Natural gas production averaged 241.4 MMcf/d compared to 225 MMcf/d in 2001. Crude oil and natural gas liquids production averaged 5,663 Bbl/d in 2002 as compared to 2,165 Bbl/d in 2001, a 162 percent increase.

Capital expenditures related to exploration and development totaled $217.2 million in 2002, including $124.1 million for exploration and development drilling; $77.4 million for production equipment and facilities; $9.3 million for geological and geophysical expenditures and $6.4 million for land. Property acquisitions net of dispositions totaled $23.6 million. A total of 135 gross wells (99.4 net) were drilled resulting in 114 natural gas wells (83.7 net), 9 oil wells (6.7 net), 11 dry and abandoned wells (8.0 net) and 1 service well (1.0 net).

Southern Alberta / Saskatchewan / Montana / North Dakota

Production through the fourth quarter from the Southern Operating Unit averaged 10.4 MMcf/d and 3,010 Bbl/d. New production additions came from the tie-in of two Mannville natural gas wells at Retlaw, Alberta in mid December. Initial combined rates from these wells totaled 1.6 MMcf/d. Paramount also participated in two new wells in the Chain area of Alberta, both of which tested gas in the Mannville. One well was tied-in and producing in December; the second will be tied-in in the first quarter of 2003. At Blaine County, Montana, Paramount also participated in a Bowes oil well. The well was completed and tested oil from the Firemoon formation. Additional completion work is contemplated for the second quarter of 2003.

The Southern Operating Unit began a process of consolidation in the fourth quarter of 2002. This process will see the Southern Operating Unit divest of smaller working interests and non-operated / non-core properties, providing an opportunity for the Company to pursue growth in core areas with higher working interests. This process, which will carry over to the first quarter of 2003, will reduce the number of individual properties from 75 to 7 or 8 core properties.

Kaybob, Alberta

Fourth-quarter production in the Kaybob Operating Unit averaged 93 MMcf/d of natural gas and 2,460 Bbl/d of crude oil and natural gas liquids. Average daily production for the year totaled 87.5 MMcf/d of natural gas and 2,290 Bbl/d of crude oil and natural gas liquids. Drilling activity within the fourth quarter was modest with 5 (2.67 net) wells drilled and rig released. A total of 38 (29.01 net) wells were drilled in the year.

Fourth-quarter drilling activity focused on developing a summer access area around Kaybob and included the farming out of a portion of Paramount's working interest. Drilling targets included all formations from Viking to Swanhills, resulting in 1.43 net gas wells, 0.49 net oil wells and 1.05 net D&A wells. A number of workovers and recompletions of low rate producers and suspended wells contributed to production increases in the operating area.

Sturgeon Lake / Grande Prairie, Alberta

During the fourth quarter, production averaged 11.3 MMcf/d of natural gas and 2,225 Bbl/d of crude oil and natural gas liquids. One (0.25 net) well was drilled and 5 (4.5 net) recompleted resulting in initial production increase of 1.5 MMcf/d and 75 Bbl/d. Activity during the first quarter of 2003 will include the drilling of 6 (3.6 net) wells and the recompletion of an additional 6 (5.7 net) others . Average production rates during the first quarter 2003 are forecast to approximate 11 MMcf/d of natural gas and 2,220 Bbl/d of crude oil and natural gas liquids. Presently, Paramount has plans to tie in 6 wells by early summer.

Northwest Alberta

In Northwest Alberta and Cameron Hills, NWT, Paramount participated in the drilling of 49 (38.6 net) wells in calendar year 2002. The vast majority of field activities relating to seismic acquisition, drilling, and construction occurred in the first quarter due to the seasonal access of the area. Natural gas sales averaged 30.4 MMcf/d in 2002. The highlight of 2002 was the tie-in of 6 natural gas wells located in Cameron Hills, NWT to processing facilities situated at Bistcho Lake in Northwest Alberta. Paramount operates and owns 60 percent of the 50 MMcf/d Bistcho Lake natural gas processing facility.

Paramount will be participating in 21 (19.2 net) wells in the Northwest Alberta region in the first quarter of 2003. In addition, Paramount anticipates bringing 5 oil wells on production in Cameron Hills. The oil will flow from Cameron through existing pipe to the Bistcho Lake facility and then on to Zama Lake and into the Rainbow pipeline system through a newly constructed line.

Liard, Northwest Territories / Northeast British Columbia

The Liard Basin continues to be an active exploration area for Paramount. As a result of the 3D seismic programs shot last year, the 2002/2003 winter drilling program is focused primarily on deep Devonian play concepts. Along the Liard fault trend, Paramount has an interest in 2-3 non-operated Devonian tests. Two of these locations are targeting potential new pools while the third is a delineation well located at the north end of the Chevron Liard Nahanni pool. At Arrowhead, along the Bovie fault trend, a farmout agreement with Anadarko includes the drilling of 4 Devonian tests as well as 3 shallower Chinkeh locations. Paramount also plans to drill 1 Mattson location northeast of the town of Fort Liard.

Average production from the Northeast, British Columbia/Northwest Territories core area increased by 32 percent from 2001 to 2002 mainly due to the addition of the Clarke Lake property as part of the Summit acquisition and the tie-in of two wells in the Maxhamish area, a-96-J and b-43-K, in the first quarter of 2002. Reserves also increased by 55 percent primarily due to the acquisition of Clarke Lake.

A Maxhamish well, b-83-K, will be tied-in during the first quarter of 2003 and the existing production and reserve recovery will continue to be optimized by installing booster compression and liquid lifting systems.

RESERVES

Paramount's year-end reserve balance for proved plus probable reserves increased 24 percent to 125 million BOE at January 1, 2003 as compared to 102 million BOE at January 1, 2002. This increased reserve balance equates to Paramount replacing its production in 2002 by 243 percent.

On a proved plus probable basis natural gas reserves increased 10 percent to 618.6 Bcf. Crude oil reserves increased 267 percent to 18.2 million barrels; and natural gas liquids reserves increased from 3.0 million barrels to 4.6 million barrels, a 53 percent increase. The acquisition of Summit Resources Limited increased reserves by 91Bcf of natural gas and 11.9 million barrels of crude oil and natural gas liquids; exploration and development expenditures increased reserves by 39 Bcf and 1.4 million barrels; additional acquisitions added 2.65 million BOE and total net positive revisions added an additional 3.2 million BOE.

Proved reserves increased 16 percent from 79.3 million BOE to 92 million BOE. This included a reduction of 6.5 million BOE from the proved category for natural gas reserves shut-in at Surmont. The transfer of the Northeast Alberta properties to Paramount Energy Trust will subsequently reduce Paramount's proved natural gas reserves by 164 Bcf and proved plus probable reserves by 203.6 Bcf..

OUTLOOK

Paramount looks forward to 2003 as commodity prices continue to rise just in time to meet the incremental production gains from our winter program. The Company estimates that it will produce approximately 38,500 BOE/d on a 6:1 basis. Capital expenditures will approximate $150 - $200 million while cash flow will approximate $250 million or $4.20 per common share. Cash flow in excess of the Company's capital expenditure program will be utilized to reduce bank indebtedness.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Paramount is pleased to report its financial and operating results for the year ended December 31, 2002.

The following discussion of financial position and results of operations should be read in conjunction with the Consolidated Financial Statements and Notes thereto. It offers Management's analysis of Paramount's historical financial and operating results and provides estimates of Paramount's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant.

Paramount Resources Ltd. ("Paramount" or the "Company") is an exploration, development and production company with established operations in Alberta, British Columbia, Saskatchewan, the Northwest Territories, Montana, North Dakota and California. The

Company has patiently executed its corporate growth strategy, focusing on natural gas as a commodity, and high impact exploration as the cornerstone to future success. Management's vision continues to be based on the long-term fundamentals for oil and natural gas in North America. During 2002, Paramount continued to focus its efforts on building a strong asset base through exploration and development, and the acquisition of Summit Resources Limited.

Significant Events

- Acquisition of Summit Resources Limited

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Highlights

- Cash flow totaled $259.9 million or $4.37 per share.

- Natural gas sales averaged 241 MMcf/d; crude oil and natural gas liquids production averaged 5,663 Bbl/d.

Accounting Policy

Paramount follows the "successful efforts" method of accounting for its petroleum and natural gas operations. This method, unlike the alternative "full cost" accounting method, usually generates a more conservative value for net earnings as exploration expenditures, including exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties as well as the cost of surrendered leases and abandoned wells are expensed rather than capitalized in the year incurred. However, to make reported cash flow results comparable to industry practice, Paramount reclassifies geological and geophysical costs as well as surrendered leases and abandonment costs from operating to investing activities.

Revenue

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Production Revenue (thousands of dollars)	2002	2001	2000
Natural gas	$ 311,438	$ 481,436	$ 375,746
Crude oil and natural gas liquids	72,750	28,442	21,676
Commodity hedging gain (loss)	46,813	15,808	(5,952)
Gain on sale of short-term investments	40,830	2,982	-
Other	2,111	(295)	-
Gross revenue	$ 473,942	$ 528,373	$ 391,470

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Paramount's financial success is contingent upon the growth of reserves and production volumes and the economic environment that creates a demand for natural gas and crude oil. Such growth is a function of the amount of cash flow that can be generated and reinvested into a successful capital expenditure program. To protect cash flow against commodity price volatility, the Company will, from time to time, manage cash flow by utilizing commodity price hedges. The hedging program is generally for periods of less than one year and restricted to a maximum of 50 percent of Paramount's current production volumes.

Petroleum and natural gas revenue totaled $431.0 million in 2002, as compared to $525.7 million in 2001 (2000 - $391.5 million). The decrease in revenue results from lower commodity prices received during the year. Weaker natural gas demand resulted in a decrease of 33% in Paramount's average natural gas sales price to $4.08/Mcf as compared to $6.12/Mcf in 2001 (2000 - $4.59/Mcf). Included in petroleum and natural gas sales are $46.8 million of commodity hedging gains attributed primarily to natural gas hedges. On a per unit basis the 2002 price includes approximately $0.55/Mcf profit from natural gas commodity hedges that were in place during the year. Natural gas sales volumes averaged 241 MMcf/d in 2002 as compared to 225 MMcf/d in 2001 (2000 - 220 MMcf/d). The increase in natural gas sales volumes is attributed to the acquisition of Summit effective June 28, 2002, which added approximately 50 MMcf/d of natural gas production.

Oil and natural gas liquids averaged $34.64/Bbl, as compared to $35.48/Bbl in 2001 (2000 - $37.80/Bbl). Oil and natural gas liquids production increased 162 percent to average 5,663 Bbl/d in 2002 as compared to 2,165 Bbl/d in 2001 (2000 - 1,571 Bbl/d). This increase is attributable to the acquisition of Summit which at the time of acquisition produced approximately 5,000 Bbl/d of oil and natural gas liquids.

Paramount's 2002 production profile continues to be significantly weighted to natural gas but the Company has increased its oil and natural gas liquids production with the Summit acquisition. In 2002 natural gas revenue contributed 83 percent of Paramount's total petroleum and natural gas revenue compared to 95 percent in 2001.

Fourth quarter petroleum and natural gas revenue totaled $135.5 million as compared to $87.7 million for the comparable quarter in 2001. The increase in sales resulted from an increase in production volumes associated with the acquisition of Summit, as well as an increase in natural gas prices, which averaged $4.60/Mcf during the quarter as compared to $4.17/Mcf for the comparable quarter in 2001. Natural gas sales averaged 263 MMcf/d for the fourth quarter of 2002 compared to 218 MMcf/d for the comparable quarter in 2001. Oil and natural gas liquids sales averaged 8,552 Bbl/d in the fourth quarter of 2002 as compared to 2,002 Bbl/d for the comparable quarter in 2001.

At December 31, 2002, Paramount had the following natural gas commodity price hedges in place representing approximately 40 percent of Paramount's average 2002 production:

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Volume		
AECO	Price	Term
10,000 GJ/d	$5.46	November 2002 - October 2003
20,000 GJ/d	$5.06	November 2002 - October 2003
20,000 GJ/d	$5.25	November 2002 - October 2003
NYMEX		
20 MMcf/d	US$3.83	November 2002 - October 2003
20 MMcf/d	US$3.90	November 2002 - October 2003
10 MMcf/d	US$4.10	November 2002 - October 2003
WTI		
1,000 Bbl/d	US$24.07	May 2002 - April 2004
1,000 Bbl/d	US$24.33	January 2003 - December 2003

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The unrealized loss on these financial hedges at December 31, 2002 totaled $28.7 million.

The Company also has in place foreign exchange hedges, which have fixed the exchange rate on U.S. $40.9 million for CDN $58.6 million over the next three years at CDN $1.4322. For the year ended December 31, 2002, gross revenue included losses from foreign currency hedging activity of $3.4 million (2001 - $1.7 million).

During 2002, approximately 43 percent of Paramount's natural gas sales were under long-term contracts to gas aggregators and direct-sales purchasers as compared to 42 percent and 46 percent for 2001 and 2000, respectively.

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Natural Gas Sales per Market Group

		2002 Bcf	2002 %	2001 Bcf	2001 %	2000 Bcf	2000 %
Long-term contracts							
Aggregators							
Mirant	Midwestern US, Pacific Northwest US, California and Quebec	14.7	16.6	17.4	21.2	19.6	24.3
Progas	Northeastern US	9.6	10.9	8.1	9.9	7.2	8.9
Canstates/Temco	Northeastern US	1.5	1.7	1.9	2.2	3.2	4.0
TransCanada	Eastern Canada	0.4	0.5	2.7	3.3	1.2	1.5
Subtotal - aggregators		26.2	29.7	30.1	36.6	31.2	38.7
Direct sales							
Nexen	Midwestern US	2.9	3.3	-	-	-	-
Selkirk	Northeastern US	6.0	6.8	4.5	5.5	6.0	7.4
West Windsor	Eastern Canada	0.6	0.7	-	-	-	-
BC Gas	British Columbia	0.6	0.7	-	-	-	-
Duke	AECO	1.4	1.6	-	-	-	-
Subtotal - direct sales		11.5	13.1	4.5	5.5	6.0	7.4
Subtotal - Long-term Contacts		37.7	42.8	34.6	42.1	37.2	46.1
Short-term markets							
Spot	Chicago	3.2	3.6	-	-	-	-
Spot	Eastern Canada	2.7	3.1	-	-	-	-
Spot	California	13.8	15.7	14.6	17.8	14.6	18.1
Spot	Alberta/ Waddington	30.7	34.8	32.9	40.1	28.7	35.8
Total(1)		88.1	100.0	82.1	100.0	80.5	100.0

(1) Natural gas sales for 2000 reflect a 366-day year

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For 2003, revenues will be impacted by drilling success and production volumes as well as external factors such as the market for natural gas, the exchange rate of the Canadian dollar relative to the U.S. dollar and the W.T.I price for crude oil. Additionally, the disposition of producing natural gas assets in Northeast Alberta to the Trust will reduce production volumes and corresponding reserves. Natural gas production in this area averaged approximately 97 MMcf/d during 2002, exiting the year at 90 MMcf/d. A minor asset disposition package is also currently being marketed, with bids expected to close early in 2003.

The Company anticipates a continued positive trend in commodity prices for 2003 relative to the prices received in 2002.

Gain On Sale of Short-Term Investments

During the year Paramount disposed of 8.7 million shares of Peyto Exploration and Development Corp. at an average price of $5.17 per share for net proceeds of $45.0 million resulting in a gain of $40.1 million. In 2002, Paramount also disposed of 1.25 million shares of Triquest Energy Corp. at an average price of $2.98 per share for net proceeds of $3.7 million resulting in a gain of $0.7 million. Paramount routinely utilizes a portion of its working capital to make short-term investments in private and publicly traded oil and gas companies. Accordingly, related gains and losses are included in cash flow from operations.

Bitumen/Natural Gas Co-Production

On February 28, 2002, Paramount entered into a Memorandum of Agreement with the Province of Alberta and Conoco Canada Resources Ltd. ("Conoco"), effective May 1, 2000. The Memorandum of Agreement provided, inter alia, for compensation of $85 million to be paid to the Surmont Gas Producers by the Alberta Crown in the form of reduced royalties as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty encompassing certain wells, lands and leases affected by the shut-in order of May 1, 2000. Compensation of $47.1 million was received in June 2002. This amount has been recorded in the Consolidated Statement of Earnings, net of the net book value of wells, lands and leases in the affected area of $9.1 million.

Royalties

Royalties are paid by Paramount to the owners of mineral rights with whom the Company holds leases. Paramount has mineral leases with the Crown (Provincial and Federal Governments), freeholders and other operators with whom the Company has joint interests.

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Royalties (thousands of dollars)	2002	2001	2000
Crown royalties	$71,535	$94,253	$76,470
Other royalties	3,658	5,953	4,587
	75,193	100,206	81,057
Alberta Royalty Tax Credit	(749)	(500)	(516)
Total royalties	$74,444	$99,706	$80,541
Average corporate royalty rate	17.2%	18.9%	20.6%

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Alberta gas Crown royalties are a cash royalty calculated on the Crown's share of production using the Alberta Reference Price. The Alberta Reference Price is the monthly weighted average price for gas consumed in Alberta and gas exported from Alberta reduced for allowances for transportation and marketing. A subsequent cost-of-service credit is applied to account for the Crown's share of allowable capital and processing fees to arrive at the net royalty.

For 2002, royalties net of the Alberta Royalty Tax Credit ("ARTC") decreased to $74.4 million from $99.7 million in 2001 (2000 - $80.5 million) due to lower natural gas commodity prices. As a percentage of production revenue, Paramount's corporate royalty rate decreased to 17.2 percent as compared to 18.9 percent in 2001 (2000 - 20.6 percent). Fourth-quarter royalties reflected the increase in production volumes and commodity prices compared to the prior year's quarter, and increased to $31.2 million as compared to $12.4 million during the fourth quarter 2001.

For 2003, Paramount's average corporate royalty rate is expected to increase, giving effect to a corporate average natural gas price which will be less than the Alberta Reference Price on which royalties are calculated. This results from expected losses on the Company's hedging program which are netted from revenues in deriving at petroleum and natural gas sales. As in 2002, there will continue to be minimal royalties paid to the Federal Government for production from projects in the Northwest Territories. Royalties for these projects are subject to payout accounts.

Operating Expenses

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Operating Expenses (thousands of dollars)	2002	2001	2000
Operating expenses	$86,067	$61,045	$47,974
Net operating expenses per Mcfeq	$0.79	$0.68	$0.56

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Paramount's 2002 operating expenses increased 38 percent to $86.1 million from $61.0 million in 2001 (2000 - $48.0 million). On a unit-of-production basis, average operating costs increased to $0.79 /Mcfeq from $0.68/Mcfeq in 2001 (2000 - $0.56/Mcfeq). Fourth-quarter operating costs increased to $21.5 million as compared to $17.5 million a year earlier, primarily due to the increased well base in the current quarter associated with the Summit acquisition.

Paramount constructs and operates plant facilities and gathering systems as a corporate strategy in order to control the flow of gas to market. These facilities incur fixed costs, which are in addition to the costs incurred at the well level, thereby increasing total operating expenses and the relative magnitude of the per unit costs. As production declines in the Company's traditional shallow gas areas, per-unit operating costs have increased. In new core areas facilities are constructed in anticipation of maximizing throughput, which in many cases has not yet been achieved. As optimization occurs and production volumes increase, per-unit costs should decrease to levels historically experienced by the Company. Operating costs associated with the Northeast Alberta assets totaled $32.3 million in 2002 or $0.91/Mcf.

For 2003, the Company expects operating costs on a per-unit-basis to decline marginally in recognition of the disposal of higher cost assets in Northeast Alberta.

General and Administrative Expenses

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General and Administrative Expenses (thousands of dollars)	2002	2001	2000
Gross general and administrative expenses	$ 30,868	$ 26,374	$ 18,982
Operating recoveries	(15,238)	(15,766)	(11,369)
General and administrative expenses before SARP	15,630	10,608	7,613
Share Appreciation Rights Plan ("SARP")	582	1,738	2,047
Net general and administrative expenses	$ 16,212	$ 12,346	$ 9,660
Net general and administrative expenses per Mcfeq	$ 0.15	$ 0.14	$ 0.11

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General and administrative expenses, net of operating recoveries and before costs associated with the Share Appreciation Rights Plan ("SARP"), increased to $15.6 million in 2002 as compared to $10.6 million in 2001 (2000 - $7.6 million). The increase is a result of additional salaries incurred in respect of the Summit office and field personnel, as well as additional administrative expenditures incurred to set up and staff the Trust. During the year, the Company increased head office staff by more than 32 percent and field staff by 62 percent in order to manage the Company's increasing asset base and to adequately staff the Trust. Cost increases associated with additional staffing levels include salary, benefits and rent. Paramount does not capitalize any general and administrative expenses.

Certain costs associated with setting up the Trust including legal and professional fees and advisory fees have been deferred and will be included as a cost associated with the disposition of the Northeast Alberta assets.

At the Annual General Meeting of the shareholders held June 14, 2001, a resolution was approved to introduce an employee stock option plan as a substitute for the SARP. Share appreciation rights previously held by employees have been grandfathered until their expiry and are capped at a price of $14.50, that being the grant price of an equal number of stock options. Under the SARP, participants are entitled to receive a benefit of an amount equal to the positive difference between the exercise price and $14.50, which difference is charged to general and administrative expenses. At December 31, 2002, 238,000 SARP's remained outstanding. Employees exercising options have the choice of receiving cash from the Company for the positive difference between the exercise price and market price of the Company shares or receiving Company shares. Cash consideration paid is charged to general and administrative costs as incurred. During 2002, 177,000 options were exercised for consideration of $0.6 million as compared to $1.7 million in 2001 (2000 - $2.0 million).

General and administrative expenses are expected to decline in 2003 as the Trust's operations will be excluded from Paramount's activities.

Interest Expense

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Interest Expense (thousand of dollars)	2002	2001	2000
Interest expense	$23,943	$19,291	$22,313
Total Debt, December 31	$539,270	$316,600	$315,000
Debt to cash flow	2.07	1.04	1.41

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Interest expense, representing interest on bank debt, increased to $23.9 million from $19.3 million in 2001 (2000 - $22.3 million). The increase reflects significantly higher average debt levels during 2002 necessary to fund the Summit acquisition and the higher interest rates charged on the facility.

To finance the acquisition of Summit, the Company negotiated a $600 million credit facility with a syndicate of Canadian Chartered banks, including a $466 million production facility, a $109 million bridge facility and a $25 million working capital facility.

The term of the credit facility was initially structured to coincide with the closing of the transfer by Paramount to the newly formed Trust of a portion of its Northeast Alberta assets. As the Trust Rights Offering did not close until March 11, 2003, Paramount requested a formal extension of the existing facility. Upon closing of the Trust transaction the proceeds received by Paramount from the sale of the assets to the Trust have been used to permanently reduce bank indebtedness. On March 11, 2003, the term of the facility was extended to April 30, 2003, the bridge facility was paid down in its entirety and the credit facility reduced to $315.5 million.

The Company had a note payable in the amount of $33 million to Paramount Oil and Gas Ltd. The note was paid in full on March 7, 2003.

Dry Hole Costs

Under the successful efforts method of accounting, costs of drilling exploratory wells are initially capitalized and, if subsequently determined to be unsuccessful, are charged to dry hole expense. All other exploration costs, including geological and geophysical costs and annual lease rentals, are charged to exploration expense as incurred. For 2002, dry hole costs amounted to $120.1 million as compared to $8.9 million in 2001 and $7.0 million in 2000. The provision includes $4.7 million of costs associated with wells drilled in the current year, $7.5 million of expired mineral leases, $41.9 million associated with exploratory wells drilled in Canada in previous years, which the Company has determined will not be capable of production in economic quantities, and $66.0 million related to certain exploratory projects in the United States which the Company has determined to be unsuccessful.

Geological and geophysical expenses decreased during 2002 to $9.3 million (2001 - $10.6 million; 2000 - $6.8 million).

Depletion, Depreciation and Amortization

The current year provision for depletion and depreciation expense totaled $169.4 million as compared to $105.4 million in 2001 (2000 - $50.6 million). On a unit-of-production basis, depletion and depreciation costs averaged $1.56 /Mcfeq as compared to $1.21/Mcfeq in 2001 (2000 - $0.59/Mcfeq). A larger depletable base due to the 2002 capital expenditure program and acquisition of Summit combined with reduced proved reserves increased the depletion factor during the fourth quarter.

Under the successful efforts method of accounting, depletion and depreciation is provided based on estimated proved recoverable reserves of each producing property. Capital costs associated with undeveloped land of $218.4 million and non-producing petroleum and natural gas properties of $148.8 million totaling $367 million are excluded from capital costs subject to depletion in 2002 (2001 - $402 million).

For 2003, the provision for depletion and depreciation is expected to decrease reflecting the disposition of assets in Northeast Alberta to the Trust and the corresponding reduction in production volumes. Increases or decreases in the depletion rate on a unit-of-production basis will be influenced by the reserves added through the 2003 drilling program or by acquisition.

Future Site Restoration and Abandonment Costs

On an annual basis the Company reviews the liability for future site restoration and abandonment costs. For 2002 the provision totaled $3.4 million as compared to $2.4 million in 2001 (2000 - $1.7 million). Current estimates for site restoration of all the Company's properties total approximately $58 million, excluding assets in Northeast Alberta which were sold to the Trust during the first quarter of 2003. At December 31, 2002, $23.0 million is reflected as an accumulated provision in the financial statements. This amount includes an accumulated provision for future site restoration of $10.6 million included as part of the acquisition of Summit Resources Limited.

Write-Down of Petroleum and Natural Gas Properties

The Company has recorded a provision of $31.3 million in 2002 (2001, 2000 - nil) in respect of impairment in certain producing non-core oil and gas assets located in Alberta and Southeast Saskatchewan.

Income Taxes

In 2002, Paramount recorded Large Corporations and other tax expense of $9.2 million as compared to $2.7 million in 2001 (2000 - $2.3 million). The Company did not pay current income tax in 2002.

The future income tax benefit recorded in 2002 totaled $46.9 million as compared to a $56.1 million provision in 2001 (2000 - $72.0 million provision). The Company also recorded a $104.9 million future tax liability in respect of the Summit acquisition, which represents the tax effect of the difference between the value attributed to the Summit capital assets and the value of the related tax pools.

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Estimated Income Tax Pools (millions of dollars)	December 31, 2002
Undepreciated capital costs (UCC)	$ 313.5
Canadian oil and gas property expenses (COGPE)	302.2
Canadian exploration expenses (CFE)	9.4
Canadian development expenses (COE)	148.1
Foreign exploration and development expenses (FEDE)	22.4
Other	0.7
Total estimated income tax pools	$ 796.3

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Paramount has available approximately $796 million of unutilized tax pools at December 31, 2002. These tax pools will be available for deduction in 2003 in accordance with Canadian income tax regulations at varying rates of amortization.

The disposition of the Northeast Alberta assets to the Trust will result in a reduction to COGPE and UCC.

Cash Flow and Earnings

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(thousands of dollars)	2002	2001	2000
Cash flow from operations	$259,916	$303,937	$223,446
Net earnings	$10,307	$118,902	$86,062
Weighted average shareholders' equity	$540,745	$477,705	$373,623
After-tax rate of return (%)	1.9	24.9	23.0

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Paramount's cash flow from operations decreased 14 percent to $259.9 million or $4.37 per basic common share ($4.36 per diluted common share) from $303.9 million or $5.11 per basic and diluted common share in 2001 (2000 - $223.4 million or $3.76 per basic and diluted common share). The decrease is due to lower natural gas prices in 2002, offset somewhat by higher gas and liquids production during the year, as a result of the Summit acquisition. Fourth-quarter cash flow totaled $62.1 million, an increase of 30 percent from $47.7 million during the same period in 2001 (2000 - $97.2 million). The weighted average common shares outstanding totaled 59.5 million in 2002, unchanged from 59.5 million in 2001 and 2000.

Earnings decreased to $10.3 million or $0.17 per basic common share ($0.16 per diluted common share) compared to $118.9 million or $2.00 per basic and diluted common share in 2001 (2000 - $86.1 million or $1.45 per basic and diluted common share). The lower earnings in 2002 are a result of decreased cash flows, as well as larger non-cash charges for depletion and depreciation, dry hole costs, and the write-down of petroleum and natural gas properties. The impact of these charges was partially offset by a significant future tax recovery.

Paramount's three-year average after-tax rate of return on a book basis, based upon the weighted average shareholders' equity invested, was 17 percent.

Netbacks

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Netbacks ($/Mcfeq)	2002	2001	2000
Revenue	$3.96	$5.87	$4.54
Royalties (net of ARTC)	0.68	1.11	0.93
Operating costs	0.79	0.68	0.56
Operating netback	2.49	4.08	3.05
General and administrative	0.15	0.14	0.11
Lease rentals	0.04	0.05	0.06
Interest on long-term debt	0.22	0.21	0.26
Current and Large Corporations tax	0.08	0.31	0.03
Cash netback	$2.00	$3.37	$2.59

Capital Expenditures

Capital Expenditures (thousands of dollars)	2002	2001	2000
Land	$ 6,410	$ 39,166	$ 24,016
Geological and geophysical	9,303	10,646	6,784
Drilling	124,076	127,736	108,811
Production equipment and facilities	77,407	94,775	92,690
Exploration and development expenditures	217,196	272,323	232,301
Summit Resources Limited acquisition	449,648	-	-
Dry hole and geological and geophysical costs expensed	(129,361)	(19,590)	(13,803)
Petroleum and natural gas property impairment	(42,183)	-	-
Property acquisitions	28,610	19,048	61,550
Property dispositions	(4,995)	(11,763)	(34,205)
Other	2,349	1,166	3,205
Net capital expenditures	521,264	261,184	249,048
Adoption of new accounting policy	-	-	14,900
Change in cost of petroleum and natural gas properties	$ 521,264	$ 261,184	$263,948

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During 2002, expenditures for exploration and development activities totaled $217.2 million as compared to $272.3 million in 2001 (2000 - $232.3 million). A total of 135 gross (99.5 net) wells were drilled during the year, including 15 gross (6.3 net) wells in the fourth quarter, compared to 196 gross (158.7 net) wells in 2001 (2000 - 163 gross, 128.7 net).

Net capital expenditures, including property acquisitions net of dispositions and the acquisition of Summit, amounted to $521.3 million in 2002 as compared to $261.2 million in 2001 (2000 -

$249.0 million).

Dry hole and geological and geophysical costs expensed totaled $129.4 million in 2002 as compared to $19.6 million in 2001 (2000 - $13.8 million). Included in this amount are $41.9 million associated with exploratory wells drilled in Canada in previous years, and $66.0 million related to exploratory projects in the United States, which the Company has determined to be unsuccessful. Seismic costs during 2002 totaled $9.3 million, as compared to $10.6 million in 2001 (2000 - $6.8 million).

In conjunction with the cash compensation received from the Alberta Crown related to the Surmont natural gas/bitumen issue, the Company has made a provision of approximately $9.1 million (net of $1.8 million accumulated depletion and depreciation) in recognition of the impairment in asset value resulting from the shut-in. The amount represents the net book value of the assets carried in the financial statements.

Paramount has also recorded a $31.3 million impairment charge in respect of producing non-core oil and gas assets located in Alberta and Southeast Saskatchewan

For 2003, Paramount's capital expenditure budget will be funded by internally generated cash flow and minor property dispositions. Any deficiency will draw upon existing credit facilities.

Investments

Short-Term Investments

The Company has the following short-term investments:

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	Opening 2002 Shares	Purchased (Sold) Shares	Closing 2002	Investment	Gain on Sale
Investments					
Peyto Exploration and Development Corp.	8,709,072	(8,709,072)	-	$ -	$40,105,111
Triquest Energy Corp.(C)	5,000,000	(5,000,000)	-	-	725,000
Fox Creek Petroleum Corp.	1,028,571	1,144,591	2,173,162	2,234,000	
Jurassic Oil and Gas Ltd.		850,000	850,000	1,020,000	
Spearhead Resources Inc.(A)				5,000,000	
Altius Energy Corp.(B)				4,690,240	
				$12,944,240	$40,830,111

(A)Spearhead Resources Inc. $5 million 8 percent secured convertible debenture due September 12, 2003
(B)Altius Energy Corp. $2.7 million U.S. 14 percent secured convertible debenture due April 9, 2005
(C)During the year Triquest shares were consolidated on a 4-for-1 basis. Actual Triquest shares sold in 2002 were 1,250,000.

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At December 31, 2002, all short-term investments were either debentures, or warrants or shares in private companies, therefore a market value for these assets is not readily accessible. The Company believes that the market value of its short-term investments approximates their book value.

Investment in Drilling Company

Paramount owns a 50 percent equity interest in Wilson Drilling Ltd., a private company established to operate 3 drilling rigs in Western Canada. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

Investment in Pipeline Company

Paramount owns a 50 percent equity interest, before payout (45 percent after payout) in Shiha Energy Transmission Ltd., a private company established to transport natural gas from operations in the Liard core area, Northwest Territories to facilities in British Columbia. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

Investment in Engineering Company

Paramount owns a 50 percent equity interest in a private company whose principal business is to provide consulting and technical engineering services. The Company accounts for its interest using proportionate consolidation whereby its pro-rata share of the financial results is combined on a line-by-line basis with similar items in the Company's financial statements.

Deferred Revenue

During 2002, Paramount recognized in revenue $39.4 million (2001 - $1.2 million; 2000 - $1.2 million) of deferred revenue primarily related to the settlement of natural gas commodity hedging contracts that were previously put in place to shelter the Company from declining gas prices. Paramount's accounting policy recognizes these gains in the accounting years of related production. The deferred hedging gains of $7.8 million at December 31, 2002 will be recognized in revenue in 2003.

Bank Debt, Liquidity and Risk Management

Paramount's debt and equity capital structure as at December 31, 2002, was as follows:

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(thousands of dollars, except per share)	AT COST Amount	%	$/Share (2)	AT MARKET(1) Amount	%	$/Share (2)
Bank debt, net of working capital	555,243	55	9.34	555,243	32	9.34
Future income taxes	271,090	27	4.56	271,090	16	4.56
Common share equity	190,193	18	3.20	891,879	52	15.00
Total	1,016,526	100	17.10	1,718,212	100	28.90

(1)Close at December 31, 2002- $15.00 /share.
(2)At December 31, 2002- 59,458,600 basic common shares outstanding.

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To finance the acquisition of Summit, the Company negotiated a $600 million credit facility with a syndicate of Canadian Chartered Banks, including a $466 million production facility, a $25 million working capital facility, and a $109 million bridge facility. Upon receipt of the Surmont proceeds the bridge facility was permanently reduced by approximately $47.1 million.

Upon closing of the Initial offering of units by Paramount Energy Trust (the "Trust"), the proceeds received by the Company in exchange for petroleum and natural gas properties sold to the Trust were used to permanently reduce bank indebtedness. Effective March 12, 2003, the available borrowing base under the current credit facility was reduced to $315.5 million.

Also of significant importance to the Company is the Canada/U.S. exchange ratio, since a substantial percentage of the natural gas sales and crude oil sales of the Company are made into and priced effectively on U.S. markets. Any improvement in the Canadian dollar relative to its U.S. counterpart will have a negative impact on the wellhead price received for our production. To manage this risk, Paramount has entered into currency swap agreements that have fixed the exchange rates on U.S. $40.9 million of future production revenue over the next three years at CDN $58.6 million. In addition, the Company's U.S. $20 million bank loan is also designated as a currency hedge.

As at December 31, 2002, the Company's issued share capital consisted of 59,458,600 common shares (December 31, 2001 and 2000 - 59,453,600 common shares). Paramount instituted a "Normal Course Issuer Bid" to acquire a maximum of 5 percent of its issued and outstanding shares commencing September 1, 2001, and ending August 31, 2002. During 2002, no shares were purchased pursuant to the plan.

Risks and Uncertainties

Companies involved in the exploration for and production of oil and natural gas face a number of risks and uncertainties inherent in the industry. The Company's performance is influenced by commodity pricing, transportation and marketing constraints and government regulation and taxation.

Natural gas prices are influenced by the North American supply and demand balance as well as transportation capacity constraints. Seasonal changes in demand, which are largely influenced by weather patterns, also affect the price of natural gas.

Stability in natural gas pricing is available through the use of short and long-term contract arrangements. Paramount utilizes a combination of these types of contracts, as well as spot markets, in its natural gas pricing strategy. As the majority of the Company's natural gas sales are priced to US markets, the Canada/US exchange rate can strongly affect revenue.

Oil prices are influenced by global supply and demand conditions as well as for worldwide political events. As the price of oil in Canada is based on a US benchmark price, variations in the Canada/US exchange rate further affect Paramount's oil price.

The Company's access to oil and natural gas sales markets is restricted, at times, by pipeline capacity. In addition, it is also affected by the proximity of pipelines and availability of processing equipment. Paramount controls as much of its marketing and transportation activities as possible in order to minimize any negative impact from these external factors.

The oil and gas industry is subject to extensive controls, regulatory policies and income taxes imposed by the various levels of government. These controls and policies, as well as income tax laws and regulations, are amended from time to time. The Company has no control over government intervention or taxation levels in the oil and gas industry; however, it operates in a manner to ensure that it is in compliance with all regulations and is able to respond to changes as they occur.

Paramount's operations are subject to the risks normally associated with the oil and gas industry including hazards such as unusual or unexpected geological formations, high reservoir pressures and other conditions involved in drilling and operating wells. The Company minimizes these risks using prudent safety programs and risk management, including insurance coverage against potential losses.

The Company recognizes that the industry is faced with an increasing awareness with respect to the environmental impact of oil and gas operations. Paramount has reviewed the environmental risks to which it is exposed and has determined that there is no current material impact on the Company's operations; however, the cost of complying with environmental regulations is increasing. Paramount will ensure continued compliance with environmental legislation.

Kyoto Protocol on Greenhouse Gas Emissions

Canada is signatory to an International Treaty to achieve a 6 percent reduction from 1990 greenhouse gas emission levels by 2008-2012, which represents approximately a 25 percent cut from current levels. At this time the Company does not know what final course of action the Canadian or United States governments will take in this regard and accordingly cannot measure the potential risk to our business.

2003 Cash Flow Forecast and Sensitivity Analysis

The Company's earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Company. Current volatility in commodity prices creates uncertainty as to Paramount's cash flow and capital expenditure budget. The Company will therefore assess results throughout the year and revise budgets as necessary to reflect most current information. The following analysis assesses the magnitude of these sensitivities on the Company's 2003 cash flow using the following base assumptions:

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a) 2003 Production	
Natural gas	180 MMcf/d
Crude oil/liquids	8,500 Bbl/d
b) 2003 Average Prices	
Natural gas	$5.80Mcf
Crude oil/liquids (W.T.I.)	$28.00/Bbl
c) Cash Flow	$240 million
d) 2003 Net Capital Expenditures	$200 million

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The following analysis assesses the estimated after-tax impact on cash flow with variations in production, price, interest and exchange rates:

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Sensitivity (millions of dollars)	Cash Flow
Gas sales change of 10 MMcf/d	13.5
Gas price change of $0.10/Mcf	4.2
Oil and natural gas liquids sales change of 100 Bbl/d	0.8
Oil and natural gas liquids price change of $1.00/Bbl (W.T.I)	2.0
Sensitivity to Canada/US exchange rate fluctuation of $0.01 CDN.	0.5
Average interest rate change of 1%	2.0

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Recent Accounting Pronouncements

Hedging Relationships

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 Company anticipates that adoption of Accounting Guideline 13 will not have a material effect on its consolidated financial statements.

Impairment of Long-Lived Assets

The CICA recently issued Handbook Section 3063 - Impairment of Long-Lived Assets. This new Section establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets by profit-oriented enterprises. The section is effective for fiscal years beginning on or after April 1, 2003.

Under the new Section, impairment of long-lived assets held for use is determined by a two-step process, with the first step determining when an impairment is recognized and the second step measuring the amount of the impairment. To test for and measure impairment, long-lived assets are grouped at the lowest level for which identifiable cash flows are largely independent. An impairment loss is recognized when the carrying amount of a long-lived asset exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is measured as the amount by which the long-lived asset's carrying amount exceeds its fair value. This represents a significant change to Canadian GAAP, which previously measured the amount of the impairment as the difference between the long-lived asset's carrying value and its net recoverable amount (i.e. undiscounted cash flows plus residual value). The potential impact of this pronouncement on the Consolidated Financial Statements is not known at present.

Disposal of Long-Lived Assets and Discontinued Operations

The CICA recently issued Handbook Section 3475 - Disposal of Long-Lived Assets and Discontinued Operations, establishes standards for the recognition, measurement, presentation and disclosure of the disposal of long-lived assets by profit-oriented enterprises. It also establishes standards for the presentation and disclosure of discontinued operations. Although earlier adoption is encouraged, section 3475 applies to disposal activities initiated by a company's commitment to a plan on or after May 1, 2003. The Company anticipates that adoption of this pronouncement will not have a material effect on its consolidated financial statements.

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Consolidated Balance Sheets

As at December 31 (thousands of dollars)	2002	2001
ASSETS (note 6)		
Current Assets		
Cash	$ -	$ 740
Short-term investments (market value: 2002 - $14,168; 2001 - $29,598) (note 14)	14,168	13,932
Accounts receivable (note 11)	91,042	72,356
Prepaid expenses	19,213	13,320
Deferred hedging loss (note 11)	-	17,638
	124,423	117,986
Property, Plant and Equipment (note 4)		
Petroleum and natural gas properties, at cost	1,961,369	1,440,105
Accumulated depletion and depreciation	(549,408)	(381,768)
	1,411,961	1,058,337
	$ 1,536,384	$1,176,323
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$ 140,396	$ 92,084
Shareholder loan (notes 7 and 15)	33,000	-
Bank loans (notes 6 and 15)	498,097	-
	671,493	92,084

Bank loans (notes 6 and 15)	-	314,148
Drilling rig indebtedness (note 5)	1,443	2,452
Mortgage (note 6)	6,730	-
Provision for future site restoration and abandonment costs	22,954	8,955
Deferred revenue (note 11)	7,804	1,427
Future income taxes (note 9)	279,855	221,873
	318,786	548,855
Commitments and contingencies (notes 5, 11 and 13)		
Shareholders' Equity		
Share capital (note 8)		
Issued and outstanding 59,458,600 common shares (2001- 59,453,600 common shares)	190,193	189,320
Retained earnings	355,912	346,064
	546,105	535,384
	$ 1,536,384	$1,176,323

See accompanying notes to consolidated financial statements

Consolidated Statements of Earnings and Retained Earnings

(thousands of dollars except for per share amounts)	Three Months Ended December 31 2002	2001	Year Ended December 31 2002	2001
Revenue				
Petroleum and natural gas sales	$ 135,501	$ 87,670	$ 431,001	$ 525,686
Royalties (net of ARTC)	(28,157)	(12,438)	(74,444)	(99,706)
Gain on sale of investments (note 14)	725	-	40,830	2,982
Other income	2,111	-	2,111	(295)
	110,180	75,232	399,498	428,667
Expenses				
Operating	23,474	17,530	86,067	61,045
Surmont compensation - net (note 10)	-	-	(37,291)	-
Interest	9,727	4,658	23,943	19,291
General and administrative	5,768	3,470	16,212	12,346
Geological and geophysical	1,182	1,739	9,303	10,646
Dry hole costs (note 4)	75,909	282	120,058	8,944
Lease rentals	1,585	1,227	4,552	4,319
(Gain) loss on sales of property and equipment	121	1,159	(12)	1,537
Provision for future site restoration and abandonment costs	1,619	600	3,437	2,400
Depletion and depreciation	61,106	59,310	169,433	105,433
Write-down of petroleum and natural gas properties (note 4)	31,254	-	31,254	-
	211,745	89,975	426,956	225,961

Earnings (loss) before taxes	(101,565)	(14,743)	(27,458)	202,706
Income and other taxes (note 9)				
Current income tax	-	-	-	25,000
Large corporations tax and other	7,866	615	9,150	2,729
Future income tax (recovery)	(68,032)	(4,925)	(46,915)	56,075
	(60,166)	(4,310)	(37,765)	83,804
Net earnings	(41,399)	(10,433)	10,307	118,902
Retained earnings, beginning of year	397,311	358,269	346,064	228,934
Adoption of new accounting policies (note 3)	-	(1,772)	(459)	(1,772)
Retained earnings, end of year	$ 355,912	$ 346,064	$ 355,912	$ 346,064
Net earnings per common share				
- basic	$ (0.70)	$ (0.18)	$ 0.17	$ 2.00
- diluted	$ (0.70)	$ (0.18)	$ 0.16	$ 2.00
Weighted average common shares outstanding (thousands)				
- basic	59,459	59,454	59,458	59,454
- diluted	59,581	59,527	59,567	59,527

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

	Three Months Ended December 31		Year Ended December 31	
Years ended December 31 (thousands of dollars except for per share amounts)	2002	2001	2002	2001
Operating activities				
Net earnings	$ (41,399)	$ (10,433)	$ 10,307	$ 118,902
Add (deduct) non-cash items				
Write-down of Surmont assets	-	-	9,136	-
Depletion and depreciation	61,106	59,310	169,433	105,433
Write-down of petroleum and natural gas properties	31,254	-	31,254	-
(Gain) loss on sales of property and equipment	121	1,159	(12)	1,537
Provision for future site restoration and abandonment costs	1,619	600	3,437	2,400
Future income taxes	(68,032)	(4,925)	(46,915)	56,075
Non-cash general and administrative expenses	342	-	342	-
Add items not related to operating activities				
Surmont compensation	-	-	(46,427)	-
Dry hole costs	75,909	282	120,058	8,944

Geological and geophysical costs	1,182	1,739	9,303	10,646
Cash flow from operations	62,102	47,732	259,916	303,937
Increase (decrease) in deferred revenue	(10,360)	(291)	6,073	(1,160)
Change in non-cash operating working capital (note 12)	(26,453)	(1,930)	40,145	(17,677)
	25,289	45,511	306,134	285,100
Financing activities				
Bank loans - draws	12,646	46,488	146,952	3,627
Bank loans - repayments	(25,219)	-	(37,516)	-
Shareholder loan	-	-	33,000	-
Capital stock	-	-	72	-
Mortgage	6,730	-	6,730	-
Drilling rig indebtedness	(83)	(45)	(1,009)	(2,027)
	(5,926)	46,443	148,229	1,600
Cash flow provided by operating and financing activities	19,363	91,954	454,363	286,700
Investing activities				
Property and equipment expenditures	14,615	54,303	209,848	266,172
Acquisition of Summit Resources Ltd. (note 2)	-	-	251,422	-
Petroleum and natural gas property acquisitions	(175)	(35,732)	28,420	8,345
Geological and geophysical costs	1,182	1,739	9,303	10,646
Proceeds on sale of property, plant and equipment	284	19,886	(4,423)	(2,857)
Surmont compensation	-	-	(46,427)	-
Change in non-cash investing working capital (note12)	3,457	51,026	6,960	4,070
Cash flow used in investing activities	19,363	91,222	455,103	286,376
Decrease (increase) in cash	-	732	(740)	324
Cash, beginning of year	-	8	740	416
Cash, end of year	$ -	$ 740	$ -	$ 740
Cash flow from operations per common share (note 3)				
- basic	$ 1.04	$ 0.80	$ 4.37	$ 5.11
- diluted	$ 1.04	$ 0.80	$ 4.36	$ 5.11
Weighted average common shares outstanding (thousands)				
- basic	59,459	59,454	59,458	59,454
- diluted	59,581	59,527	59,567	59,527

See accompanying notes to consolidated financial statements

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(all tabular amounts expressed in thousands of dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Paramount Resources Ltd. (the "Company") is involved in the exploration and development of petroleum and natural gas primarily in Western Canada. The consolidated financial statements are stated in Canadian dollars and have been prepared by management in accordance with Canadian generally accepted accounting principles.

As 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 Company's accounting policies summarized below.

(a) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Paramount Resources Ltd. and its wholly owned subsidiaries Paramount Energy Trust, Paramount Resources US LLC, 586319 Alberta Ltd., Summit Resources Ltd., Summit Resources Inc., 977554 Alberta Ltd. and 910083 Alberta Ltd.

The Company accounts for its interest in a drilling company, a drilling partnership, a pipeline company, and an engineering company where it exercises joint control using proportionate consolidation whereby its pro-rata share of all assets, liabilities, revenues and expenses are combined on a line-by-line basis with similar items in the Company's financial statements.

(b) JOINT OPERATIONS

Certain of the Company's exploration, development and production activities related to petroleum and natural gas are conducted jointly with others. These financial statements reflect only the Company's proportionate interest in such activities.

(c) SHORT-TERM INVESTMENTS

Short-term investments consist of common shares and convertible instruments held for sale. These investments are carried at the lower of cost and market value.

(d) INVENTORY

Natural gas in storage is carried at the lower of cost and net realizable value. Cost includes all amounts incurred to produce or purchase the related gas, transportation to the storage facility and the cost of storage. At December 31, 2002 and 2001, there was no natural gas inventory.

(e) PETROLEUM AND NATURAL GAS PROPERTIES

The Company follows the "Successful Efforts" Method of accounting for petroleum and natural gas operations. Under this method the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net cost of unproductive exploratory wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. Gains or losses are recognized on the disposition of property, plant and equipment.

Depletion and depreciation of petroleum and natural gas properties including well development expenditures, production equipment, gas plants and gathering systems are provided on the unit-of-production method based on estimated proven recoverable reserves of each producing property or project. Depreciation of other equipment is provided on a declining balance method at rates varying from 4 to 30 percent.

Producing areas and significant unproved properties are assessed annually, or as economic events dictate for potential impairment. Any impairment loss is the difference between the carrying value of the asset and its undiscounted net recoverable amount.

(f) FUTURE SITE RESTORATION AND ABANDONMENT COSTS

Estimated future site restoration and abandonment costs are provided for in the financial statements. This estimate, net of expected recoveries, includes the cost of equipment removal and environmental cleanup based upon current regulations and economic circumstances at year end. Actual site restoration costs are deducted from the provision in the year incurred.

(g) FOREIGN CURRENCY TRANSLATION

The Company's foreign operations are considered integrated and are translated into Canadian dollars using the temporal method.

Monetary assets and liabilities denominated in U.S. dollars are translated into Canadian dollars at exchange rates in effect at the balance sheet date. Other assets and liabilities are translated at the rates prevailing at the respective transaction dates. Revenues and expenses are translated at the average rate prevailing during the year. Translation gains and losses are reflected in income when incurred.

(h) FINANCIAL INSTRUMENTS

The Company utilizes derivative financial instrument contracts to manage its exposure to petroleum and natural gas prices, the Canadian/US dollar exchange rate and interest rate fluctuations. Gains or losses from foreign exchange and commodity hedge contracts are recognized as part of petroleum and natural gas sales in the same period as the related production revenue. Amounts received or paid under interest rate swaps are recognized in interest expense as incurred. The fair values of these contracts are not reflected in the financial statements. The Company does not enter into derivative instruments for trading or speculative purposes.

The Company's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified future revenue stream. The Company 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 derivative financial instrument contracts that have been terminated or cease to be effective prior to maturity, are deferred as other 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.

(i) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation and impairment of petroleum property and equipment and for site restoration and abandonment are based on estimates of reserves, future costs, petroleum and natural gas prices and other relevant assumptions. By their nature, these estimates and those related to the future cash flow used to assess impairment are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

(j) INCOME TAXES

The Company follows the liability method of tax accounting for income taxes. Under this method, future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs.

(k) STOCK OPTION PLAN

The Company has a stock based compensation plan consisting of a stock option plan and a stock appreciation rights plan. These plans are described in note 8.

As options granted under the Company's employee stock option plan are issued at current market value, the option has no intrinsic value and therefore no compensation expense is recorded when the options are granted. Consideration paid by employees or directors on the exercise of stock options is credited to share capital.

Awards issued under the stock appreciation plan, that call for settlement in cash or other assets, are measured as the amount by which the quoted market value of the shares of the Company's stock covered by the grant exceeds the market price of the underlying stock. Changes, either increase or decreases, in the quoted market value of those shares between the date of grant and the measurement date result are charged to earnings in the period of change.

2. ACQUISITION OF SUMMIT RESOURCES LIMITED

On May 12, 2002, Paramount and Summit Resources Limited ("Summit") jointly announced that they had entered into an agreement pursuant to which Paramount will make an offer to purchase all of the issued and outstanding common shares of Summit for cash consideration of $7.40 per share or approximately $251.4 million, including acquisition costs. This transaction has been accounted for using the purchase method and is being accounted for as of the closing date of June 28, 2002.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. The Company has not yet completed its final evaluation of the assets acquired and the liabilities assumed. Therefore, the purchase price is subject to change.

/T/

Assets	
Accounts receivable	$ 13,997
Petroleum and natural gas properties	449,648
	463,645
Liabilities	
Accounts payable	21,947
Future income taxes	104,897
Debt	74,513
Site restoration	10,562
Other liabilities	304
	212,223
Net assets acquired	$ 251,422

/T/

3. CHANGE IN ACCOUNTING POLICY

(a) STOCK-BASED COMPENSATION

Effective January 1, 2002, the Company adopted the new Canadian Institute of Chartered Accountants Standard on Stock-Based Compensation. Under this new standard, the Company's stock options and SARs, which can be settled in cash at the discretion of the employee, are accounted for at an amount equal to the difference between the exercise price and the fair value at the date of grant, resulting in a liability and corresponding compensation expense being recognized. The awards are remeasured at each reporting date. As permitted by the new standard, the Company applied the change retroactively for the SARs without restatement of individual prior periods. The impact of the adoption of the new standard on the financial statements as at January 1, 2002, was as follows:

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Increase in liability	$ 459	
Decrease in retained earnings		$ 459

/T/

The recognized expense for the year ended December 31, 2002, was $342,000.

This new standard requires the presentation of pro forma net earnings as if the Company had accounted for its employee stock options granted after December 31, 2001, under the fair value method. Had compensation cost for the Company's stock-based compensation plans been determined based on the fair value at the grant date of these awards, the Company's net earnings and earnings per share would have been reduced to the pro forma amounts indicated below:

/T/

		Year ended December 31, 2002
Net earnings	as reported	$ 19,072
	pro forma	$ 19,023
Net earnings per common share - basic	as reported	$ 0.32
	pro forma	$ 0.32
Net earnings per common share - diluted	as reported	$ 0.31
	pro forma	$ 0.31

/T/

The fair value for these options was estimated at the date of granting using a Black-Scholes Option Pricing Model with the following assumptions: weighted-average risk-free interest rate of 5.8%; dividend yield of 0%; weighted-average volatility factor of the expected market price of the Company's common shares of 39.5%; and a weighted-average expected life of the options of 4 years.

(b) TREATMENT OF FOREIGN EXCHANGE GAINS AND LOSSES ON LONG-TERM DEBT

In accordance with a newly issued Canadian Institute of Chartered Accountants ("CICA") accounting standard, the Company no longer defers and amortizes the gains or losses on foreign currency denominated long-term debt. Such gains or losses are reflected in the Income Statement in the period incurred. The new standard has been applied retroactively without restatement of prior periods. The impact of the new standard on the results of the year ended December 31, 2002 was to increase net income by $0.4 million and reduce current assets and retained earnings by $1.8 million, representing the cumulative deferred foreign exchange losses at the beginning of the period.

(c) BANK LOANS

On January 1, 2002, the Company adopted the new CICA recommendation regarding Balance Sheet Classification of Callable

Debt Obligations and Debt Obligations Expected to be Refinanced. All borrowings where the lender has the right to demand repayment within 12 months (other than in the event of a default or breach of covenants) or where the lender has the right to refuse to roll-over the borrowing for a further lending period of longer than 12 months are required to be classified as current liabilities.

The impact of this change has been to increase current liabilities by the amount of any such borrowings then in place. At December 31, 2002, this change has increased current liabilities by $498.1 million and reduced long-term bank loans by a corresponding amount.

4. PROPERTY PLANT AND EQUIPMENT

/T/

	2002		2001	
	Cost	Accumulated depletion and depreciation	Cost	Accumulated depletion and depreciation
Petroleum and natural gas properties	$1,263,544	$326,074	$919,667	$188,826
Gas plants, gathering systems and production equipment	670,769	214,655	507,976	185,527
Other	27,056	8,679	12,462	7,415
	$1,961,369	$549,408	$1,440,105	$381,768
Net book value		$1,411,961		$1,058,337

/T/

Capital costs associated with non-producing petroleum and natural gas properties totaling approximately $367 million (2001 - $402 million) are currently not subject to depletion.

The Company follows the Successful Efforts method of accounting for petroleum and natural gas operations. Under this method, the Company capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. The cost of unproductive wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender. For the year ended December 31, 2002, the Company expensed $120.1 million in dry hole costs (2001- $8.9 million), of which $66.0 million related to exploratory projects in the United States. A portion of the dry hole costs expensed related to prior year capital projects that were determined in the current year to have no future economic value. An additional provision of $31.3 million has been recorded in respect of properties in Alberta and Saskatchewan whose net book values were in excess of undiscounted reserve values at December 31, 2002.

5. JOINT VENTURES

The consolidated financial statements include the Company's proportionate share of the assets and liabilities of its joint ventures as follows:

/T/

	2002	2001
Assets		
Current assets	$ 1,278	$ 1,983
Property, plant and equipment	8,520	6,822
	$ 9,798	$ 8,805
Liabilities and equity		
Current liabilities	$ 9,239	$ 6,908
Other liabilities	2,008	3,541
Deficit	(1,449)	(1,644)
	$ 9,798	$ 8,805
Revenues	$ 2,591	$ 1,842
Net earnings (loss)	$ 195	$ (1,542)
Cash flow provided by (used in)		
Operating activities	$ 3,452	$ 2,654
Financing activities	$ 1,063	$ (1,027)
Investing activities	$ (4,515)	$ (1,627)

/T/

Wilson Drilling Ltd. had a reducing term loan facility available to a maximum of $6.0 million at December 31, 2002. The loan is repayable in equal quarterly installments of $500,000 to December 2005. As at December 31, 2002, this facility had an effective interest rate of 5.5 percent (December 31, 2001 - 5.25 percent). Wilson Drilling Ltd. also has a long-term capital lease on one of its drilling rigs with a Canadian Chartered Bank in the amount of approximately $3 million. The lease runs until August 2007 and has an imputed interest rate of 8.9%. The Company has provided a guarantee as collateral for these facilities. Earnings attributed to services provided to the Company have been eliminated from the accompanying consolidated statement of earnings.

6. BANK LOANS

To finance the acquisition of Summit, the Company negotiated a $600 million credit facility with a syndicate of Canadian Chartered Banks, including a $466 million production facility, a $109 million bridge facility and a $25 million working capital facility. The term of the facility is to April 30, 2003. Available borrowings under the bridge facility were permanently reduced by $47.1 million upon receipt of the Surmont settlement.

The term of the credit facility was initially structured to coincide with the closing of the transfer by Paramount of a portion of its Northeast Alberta assets to a newly formed Energy Trust. However, as this transaction had not yet closed as of

December 31, 2002, Paramount has requested a formal extension of the existing facility. Accordingly, the loan facility has been classified as short-term. Upon closing of the "Trust" transaction proceeds received by Paramount from the sale of the assets to the Trust will be used to permanently reduce bank indebtedness (see note 15).

The Company has provided a first floating charge over all the assets and a limited recourse guarantee from Paramount Oil and Gas Ltd., a related entity with a significant ownership interest in the Company. The facility bears interest at prime rates, bankers acceptance rates or libor rates plus a margin ranging from 250 to 800 basis points. On October 1, 2002, the margins increased by 50 basis points and increased by the same amount on the first day of each month thereafter. There are no contractual repayment requirements under this facility.

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As at December 31, the following amounts were drawn under this facility:

	2002	2001
Production/working capital facility - current interest rate of 7.5%	$ 418,570	$ -
Bridge facility - current interest rate of 13%	44,900	-
LIBOR advances - current interest rate of 7.75% (2001 - 3.2%)	31,556	31,914
Wilson Drilling bank loan - current interest rate of 5.5%	3,071	-
Bankers' acceptances - 30 day average rate of 5.25% in 2001	-	282,234
	$ 498,097	$ 314,148

/T/

The Company has an office building which was acquired as a result of the acquisition of Summit Resources Limited. The building is mortgaged at an interest rate of 6.15 percent over a term of 5 years ending December 31, 2007.

The Company has letters of credit totaling $13.3 million outstanding with a Canadian Chartered Bank. These letters of credit reduce the amount available under the Company's existing credit facility.

7. RELATED PARTY TRANSACTIONS

The Company has an unsecured note payable in the amount of $33 million (2001 - nil) to Paramount Oil and Gas Ltd. The note bears interest at bank prime plus 1 percent, and is repayable upon closing of a proposed rights offering by Paramount Energy Trust (see note 15). The effective interest rate on the note during 2002 was 5.5%.

8. SHARE CAPITAL

Authorized Capital

The authorized capital of the Company is comprised of an unlimited number of non-voting preferred shares without nominal or par value, issuable in series, and an unlimited number of common shares without nominal or par value.

/T/

Issued Capital

Common Shares	Number	Consideration
Balance December 31, 2000 and 2001	59,453,600	$ 189,320
Stock options exercised during the year	5,000	72
Expenses recognized in respect of stock-based compensation during the year	-	801
Balance December 31, 2002	59,458,600	$ 190,193

/T/

The Company instituted a Normal Course Issuer Bid to acquire a maximum of 5 percent of its issued and outstanding shares commencing September 1, 2001, and ending August 31, 2002. During 2002 and 2001, no shares were purchased pursuant to the plan.

Stock Option Plan/Share Appreciation Rights Plan

During 2001, the Company replaced the Share Appreciation Rights Plan (SARP) with an employee stock option plan. Under the plan, stock options are granted at the current market price on the date of issuance. Options granted vest over four years and have a four-and-a-half year contractual life. Share appreciation rights previously held by employees will be grandfathered until their expiry on January 31, 2004, and will be capped at a price of $14.50, that being the grant price of an equal number of stock options. Under the SARP, participants are entitled to receive a benefit of an amount equal to the positive difference between the exercise price and $14.50, which difference will be charged to general and administrative expenses. At December 31, 2002, 238,000 SARPs remained outstanding (December 31, 2001 - 479,000 SARPs) . During 2002, 177,000 SARPs were exercised at a cost of $0.6 million (2001 - 329,500 SARPs, $1.7 million), which amount is charged to general and administrative expenses.

As at December 31, 2002, 2.4 million stock options were reserved for issuance under the Company's Employee Incentive Stock Option Plan, of which 1.9 million shares are outstanding, exercisable to September 30, 2006, at prices ranging from $12.00 to $16.50 per share.

/T/

SARPs/Stock options	2002		2001	
	Average grant price	Rights/ Options	Average grant price	Rights/ Options
Balance, beginning of year	$14.08	2,173,500	$12.72	1,184,500

Granted	15.90	80,000	14.33	1,694,500
Exercised	12.98	(195,000)	14.93	(329,500)
Cancelled	14.23	(109,000)	14.16	(376,000)
Balance, end of year	$14.25	1,949,500	$14.08	2,173,500
SARPs/Options exercisable, end of year	$14.35	738,500	$13.23	213,500

The following summarizes information about stock options/SARPs outstanding at December 31, 2002:

Year of grant	Number outstanding at December 31, 2002	Weighted remaining contractual life (years)	Weighted average exercise price/share	Number exercisable at December 31, 2002	Weighted average exercise price/share
2002	80,000	4	$15.90	-	-
2001	1,631,500	3	$14.35	618,000	$14.55
2000	167,000	2	$13.00	55,500	$13.00
1999	56,000	2	$14.00	50,000	$14.00
1998	15,000	1	$12.00	15,000	$12.00
	1,949,500		$14.25	738,500	$14.35

9. INCOME TAXES

The income tax provision differs from the expected income taxes obtained by applying the Canadian corporate tax rate to income before taxes as follows:

	2002	2001
Corporate tax rate	42.14%	43.18%
Calculated income tax (recovery) expense	($11,571)	$87,528
Increase (decrease) resulting from:		
Non-deductible Crown charges, net of Alberta Royalty Tax Credit	10,449	41,394
Federal resource allowance	(29,958)	(45,215)
Provincial income tax rate adjustment	(2,758)	(8,842)
Large Corporation Tax and other	9,150	2,729
Non-taxable portion of gain on sale of investments	(8,603)	-
Other	(4,474)	6,210
Income tax (recovery) expense	($37,765)	$83,804

COMPONENTS OF FUTURE INCOME TAXES

The net future tax liability comprises:	2002	2001
Differences between tax base and reported amounts of depreciable assets	$ 285,201	$ 217,617
Share issue costs	(155)	(190)
Provision for future site restoration	(7,255)	(2,867)
Deferred hedging loss	-	5,648

Other	2,064	1,665
	$ 279,855	$ 221,873

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As at December 31, 2002, the Company has tax pools of approximately $796.3 million (2001 - $562.1 million) available for deduction against future taxable income.

10. SURMONT COMPENSATION

During 2000, the Alberta Energy and Utilities Board issued a decision regarding the Surmont natural gas/bitumen co-production issue. As a result of this decision, the Board ordered the shut-in of approximately 22 MMcf/d of the Company's production. On February 28, 2002, the Company and the Surmont Gas Producers entered into a Memorandum of Agreement with the Province of Alberta effective May 1, 2000. The Memorandum provided for compensation of approximately $85 million to be paid to the Surmont Gas Producers by the Alberta Crown in the form of reduced royalties, as well as the granting to the Province of Alberta by the Surmont Gas Producers of an 11 percent gross overriding royalty encompassing certain wells, land and leases affected by the shut-in order of May 1, 2000.

In June 2002, the Company received approximately $47 million in the form of reduced royalties from the Province of Alberta as compensation for its proportionate share of the settlement. The cash settlement, net of the net book value of wells, lands and leases in the affected area of approximately $9 million, has been recorded in net earnings in the current period.

11. FINANCIAL INSTRUMENTS

The Company's financial instruments included in the Consolidated Balance Sheet are comprised of cash, short-term investments, accounts receivable, accounts payable and accrued liabilities, shareholder loan, bank loan, mortgage and drilling rig indebtedness.

(a) FOREIGN EXCHANGE HEDGES

The Company has entered into the following currency index swap transactions, fixing the exchange rate on receipts of US $40.9 million for CDN $58.6 million over the next three years at CDN $1.4322. The US$/CDN$ closing exchange rate was 1.5776 as at December 31, 2002, (December 31, 2001 - 1.5928).

/T/

Year of settlement	U.S. dollars	Weighted average exchange rate
2003	$16,570	1.4302
2004	12,360	1.4333
2005	12,000	1.4337
	$40,930	1.4322

/T/

At December 31, 2002 the estimated fair value of these hedges based on the Company's assessment of available market information was a loss of $6.0 million (2001 - loss of $4.6 million).

(b) NATURAL GAS COMMODITY PRICE HEDGES

At December 31, 2002, the Company has entered into financial forward sales arrangements as follows:

/T/

AECO	Price	Term
10,000 GJ/d	$5.46	November 2002 - October 2003
20,000 GJ/d	$5.06	November 2002 - October 2003
20,000 GJ/d	$5.25	November 2002 - October 2003
NYMEX		
20 MMcf/d	US$3.83	November 2002 - October 2003
20 MMcf/d	US$3.90	November 2002 - October 2003
10 MMcf/d	US$4.10	November 2002 - October 2003
WTI		
1,000 Bbl/d	US$24.07	May 2002 - April 2004
1,000 Bbl/d	US$24.33	January 2003 - December 2003

/T/

Had these financial contracts been settled on December 31, 2002, using prices in effect at that time, the mark to market before tax loss would have totaled $28.7 million.

During 2002, $46.8 million of net gains related to commodity hedging contracts (2001 - $15.8 million net gains) are included in petroleum and natural gas sales.

(c) FAIR VALUES OF FINANCIAL ASSETS AND LIABILITIES

Borrowings under bank credit facilities and the issuance of commercial paper are for short periods and are market rate based, thus, carrying values approximate fair value. Fair values for derivative instruments are determined based on the estimated cash payment or receipt necessary to settle the contract at year-end. Cash payments or receipts are based on discounted cash flow analysis using current market rates and prices available to the Company.

The fair values of other financial instruments, including cash, accounts receivable, accounts payable and accrued liabilities, shareholder loan and bank loans, approximate their carrying values due to the short-term maturity of those instruments.

The fair values of the mortgage and drilling rig indebtedness approximate their carrying values, as there have been no significant changes in long-term interest rates from the dates these liabilities were incurred to the balance sheet date.

(d) CREDIT RISK

The Company is exposed to credit risk from financial instruments to the extent of non-performance by third parties, and non-performance by counterparties to swap agreements. The Company minimizes credit risk associated with possible non-performance by financial instrument counterparties by entering into contracts with only highly rated counterparties and controls third party credit risk with credit approvals, limits on exposures to any one counterparty, and monitoring procedures. The Company sells production to a variety of purchasers under normal industry sale and payment terms. The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal credit risks.

12. CHANGE IN NON-CASH WORKING CAPITAL

/T/

	2002	2001
Change in non-cash working capital:		
Short-term investments	$ (236)	$ 11,257
Accounts receivable	(18,686)	37,137
Prepaid expenses	(5,893)	(4,862)
Deferred hedging loss	17,638	(17,638)
Accounts payable and accrued liabilities	48,312	(47,641)
Less working capital deficiency acquired (note 2)	(7,950)	-
	$33,185	$(21,747)
Operating activities	$40,145	$(17,677)
Investing activities	(6,960)	(4,070)
	$33,185	$(21,747)

Amounts paid during the year related to interest and large corporations and other taxes were as follows:

	2002	2001
Interest paid	$23,278	$ 19,135
Large corporations and other taxes paid	$20,447	$ 2,729

/T/

13. CONTINGENCIES

The Company is party to various legal claims associated with the ordinary conduct of business. The Company does not anticipate that these claims will have a material impact on the Company's financial position.

14. GAIN ON SALE OF INVESTMENTS

During the year, the Company recorded gains on disposal of its investments in Peyto Exploration and Development Corp. and other short-term investments of $40.8 million.

15. SUBSEQUENT EVENTS

(a) On February 3, 2003, the Company transferred to Paramount Energy Trust (the "Trust") assets in the Legend area of Northeast Alberta for proceeds of $81 million, including 9,907,767 Trust units and a $30 million note payable.

(b) On February 3, 2003, the Company declared a dividend-in-kind of an aggregate 9,907,767 Trust units. The dividend was paid to holders of the Company's common shares of record on the close of business February 11, 2003.

(c) In March 2003, the Company disposed of a significant portion of its Northeast Alberta natural gas properties to the Trust, the majority unit holder of which is also a majority shareholder of the Company. The Company received net proceeds on disposition of $209 million, which proceeds were used to reduce bank indebtedness.

As a result of the disposition, the Company's borrowing base on its credit facility was reduced to $315.5 million.

16. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform with the current year's financial statement presentation.

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