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Toronto Stock Exchange under "ENT.un" on Friday November 28, 2003. After the transaction, the Trust had a total of 18,951,556 trust units issued and outstanding. In addition, New Enterra had a total of 2,000,000 exchangeable shares issued and outstanding.

The registered office of the Corporation is located at Suite 3300, 421 th Avenue S.W., Calgary, Alberta, T2P 4K9 and its head office is located at Suite 2600, 500-4th Avenue S.W., Calgary, Alberta T2P 2V6.

Our business

Enterra operates in Canada as an oil and gas income trust. Our current production is approximately 6,500 to 7,000 BOE/D and our established reserves (including the January 2004 purchase of properties in East Central Alberta) are approximately 12 MBOE. We pays a monthly distribution to its unitholders. This amount was set at US$0.10 for the first three distributions and was recently increased to US$0.11 for the March 2004 distribution (which is to be paid on April 15, 2004). Our growth will come mainly from future acquisition of properties to replenish our reserves. These acquisitions will be financed in part with additional debt and with the issuance of trust units.

Business Strategy

Enterra s business strategy is to grow its reserves and distributions by acquiring properties which provide additional production and potential for development upside. Enterra is focused on per unit growth. We will finance acquisitions with both debt and equity, the optimal mix being one which minimizes unitholders dilution while maintaining a strong balance sheet. Enterra s ability to replace and grow its reserves over time is the key success factor in our business strategy.

Properties

Enterra's core areas included the Peace River Arch area of Alberta, Central Alberta and East Central Alberta. Enterra also has a large inventory of prospects, the development of which could significantly increase the size of Enterra s existing production and reserve base.

Peace River Arch of Alberta

Clair

The Clair property is located 13 km north of the city of Grande Prairie, Alberta. Enterra s assets include a 100% working interest in 3,840 acres of land, 20 producing oil wells and an oil treating facility. Gas is conserved and processed at the Encana Sexsmith gas plant.

Production is primarily from the Doe Creek (Dunvegan) formation with a small amount of gas production from the Charlie Lake and Halfway. Production is light, 44 degree API gravity crude and solution gas is produced from the Doe Creek oil pool. At December 31, 2003 there were 20 oil wells producing a combined 2,175 bbl/d of oil and 2.1 mmcf/d of solution gas. One dually completed Charlie Lake and Halfway gas well also produces combined daily gas of 400 mcf/d. Enterra has a 100% working interest in this well. To date, Enterra has drilled or recompleted 29 wells for oil and seven wells for water injection. There are no further drilling plans for the pool. Enterra has received waterflood approval in June 2003 (with two recent amendment approvals) and is in the final stages of achieving 100% voidage replacement pending minor waterflood modifications. Nine wells shut-in in 2003 due to excessive gas production will be reactivated once pressure support from the waterflood is received at the wells.

Total proved reserves assigned to the Doe Creek A (Dunvegan) pool are 1,997 mbbl of oil, 1,236 mmcf of gas and 38 mbbl of natural gas liquids. Total proved and probable reserves assigned to the Doe Creek A (Dunvegan) pool are 2,998 mbbl of oil, 1,633 mmcf of gas and 51 mbbl of natural gas liquids. The probable reserves category contains the incremental reserves and net present value of the waterflood. McDaniel and Associates have stated that the additional reserves associated with the waterflood would be moved into the proven category in a staged approach. Critical stages include the achievement of 100% voidage replacement and continued performance. Total proved reserves assigned to the 13-07-073-5W6 Charlie Lake / Halfway gas well are 256 mmcf of gas and 8 mbbl of natural gas liquids. Total proved and probable reserves assigned to the Charlie Lake / Halfway gas well are 368 mmcf of gas and 11 mbbl of natural gas liquids.

Enterra also owns and operates a central oil treating facility at Clair which was connected into the Pembina Peace Pipeline system in September 2003.

Gordondale

The Gordondale property is located 75 km northwest of the city of Grande Prairie, Alberta. Enterra s assets included an average working interest of 79% in 6,240 gross acres of land as well as two flowing gas wells, one gas well awaiting tie in and one oil well. Production is currently from the Upper Kiskatinaw and Halfway zones. Enterra s share of production for the property was 300 mcf/d of gas, 8 bbl/d of oil and 4 bbl/d of natural gas liquids. The property was sold in December 2003.

McDaniel and Associates had assigned Company s share of total proved reserves to Gordondale of 164 mmcf of gas, 2 mbbl of oil, and 2 mbbl of natural liquids. Total proved and probable reserves were 217 mmcf of gas, 3 mbbl of oil, and 3 mbbl of natural gas liquids.

Rolla

The Rolla property is located 70 km north of the city of Grande Prairie, Alberta. Enterra s assets include a 50% working interest in 1,920 acres of land, 3 operated producing gas wells and a 12.5% working interest in two field compressors. Enterra s share of current gas production is approximately 800 mcf/d from three 50% working interest Dunvegan gas wells. This gas is processed at the Duke Midstream, Gordondale East gas plant.

Total proved reserves assigned to the Dunvegan are 512 mmcf of gas, and total proved and probable reserves assigned to the Dunvegan are 725 mmcf of gas. All of the proved reserves are in the proved producing category. The Dunvegan sand development in the Rolla area is part of a large Delta complex from the northwest.

Hines Creek

The Hines Creek property is located 150 km north of the city of Grande Prairie, Alberta. Enterra s assets include a 50% working interest in 5,760 acres of land, one producing gas well and one shut-in gas well currently awaiting a fracture stimulation. Enterra s share of current gas production is approximately 850 mcf/d from the 50% working interest well, and expects Enterra s share of production from the 50% working interest shut-in well to be in excess of 200 mcf/d.

Total proved reserves assigned to the Hines Creek property are 728 mmcf of gas, and total proved and probable reserves are 882 mmcf of gas. All of the proved reserves are in the proved producing category.

East Central Alberta

Sounding Lake

The Sounding Lake package is located 10 km southwest of the town of Provost, Alberta. Enterra s assets include an average working interest of 58.7% in 5,496 gross acres of land as well as 56 producing oil wells and 2 producing gas wells. Production is obtained primarily from the Dina, Cummings and Belly River formations. The three main oil pools are Sounding Lake West, Sounding Lake East, and Sounding Lake North. Enterra s share of current production for the entire area is 520 bbl/d of oil and 1,700 mcf/d of gas. Enterra has and continues to upgrade pump sizes to maximize oil production and upgrade oil batteries to handle higher volumes of total fluid and injection water. Enterra has also tied-in the flared solution gas from two of its key facilities in the area.

Enterra was assigned proved reserves at Sounding Lake of 741 mbbl of oil and 1,451 mmcf of natural gas. Total proved and probable reserves are 926 mbbl oil and 1,870 mmcf natural gas based on improved performance from the existing wells.

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Central Alberta

Sylvan Lake

The Sylvan Lake property is located 40 km west of the town of Red Deer, Alberta. Enterra s assets include an average working interest of 74.8% in 4,320 gross acres of land as well as 24 producing oil wells and 1 producing gas well. Enterra completed the development of 40-acre spacing wells in the Pekisko G pool, increasing the number of producing wells from five to 24 wells. The property currently produces 1,225 bbl/d (gross), 1,100 bbl/day (net) of 14 degree API oil from 24 wells with 850 mcf/d (net) of associated gas plus an additional 30 mcf/d (net) of non-associated gas. Production is flowlined into a central treating facility constructed in September 2003 which is owned and operated by Enterra Energy. Non-associated gas is conserved and flowlined to the Husky Sylvan Lake gas plant. Clean oil is trucked from the facility to sales.

McDaniel and Associates has assigned total proved reserves of 1,814 mbbl of oil, 1,014 mmcf of solution gas, and 32 mmcf of non-associated gas to this property. Total proved and probable reserves are 2,404 mbbl of oil, 1,344 mmcf of solution gas, and 40 mmcf of non-associated gas. Probable reserves were assigned based on an assumption that the wells will achieve a slightly higher oil recovery than estimated. Based on the success of the 2003 drilling program, Enterra plans to drill seven wells with further downspacing in the centre of the pool as well as initiate a waterflood feasibility study for the pool. The reservoir has net pays up to 40 m (130 ft). Enterra owns a 3-D seismic program that covers the Sylvan Lake Pekisko G pool.

Kaybob

This property is located 50 kilometers north of Edson, Alberta and is pipeline connected to a major gas and oil processing facility in the area. There is one well with a working interest of 100% on production in this property. With the construction of a pipeline tie-in in September 2003 and the addition of a gas-lift system in November 2003, the well was returned to production. The well is producing 130 bbl/d light crude oil with 110 mcf/d of associated gas.

McDaniel and Associates have assigned total proved reserves of 391 mbbl of oil, 230 mmcf of gas, and 8 mbbl of natural gas liquids to this property. Total proved and probable reserves are 548 mbbl of oil, 323 mmcf of gas, and 11 mbbl of natural gas liquids. Enterra acquired its interest in the Kaybob South Nisku C Pool in the year 2000. Enterra owns a 90% working interest in 320 acres of land, subject to a 7.5% NCORR on 100% of production. Enterra has a licensed copy of a 7 square mile 3-D program over the well and adjacent lands.

Reserves and Present Value Summary

Enterra is required to comply with the National Instrument 51-101, issued by the Canadian Securities Administrators, in all its reserves related disclosures. NI 51-101 came into effect on September 30, 2003 and is applicable for financial years ended on or after December 31, 2003. NI 51-101 brought about significant changes in which reporting issuers manage and publicly disclose information relating to their oil and gas reserves, mandates annual disclosure requirements and prescribes new reserve definitions as follows:

Proved reserves (P90) - this is a conservative estimate of remaining reserves. For reported reserves this means there must be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves.

Proved plus Probable (P50) - this is a reasonable estimate of remaining reserves. For reported reserves there must be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable reserves. The probable reserves will no longer be risked by 50 percent as they are implicitly risked due to the nature of the new definition of reserves.

The purpose of NI 51-101 is to enhance the quality, consistency, timeliness and comparability of oil and gas activities by reporting issuers and elevate reserves reporting to a higher level of accountability.

In the United States, registrants [other than foreign private issuers] are required to disclose reserves using the standards contained in U.S. Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with United States Statement of Financial Accounting Standards No.69 "Disclosures About Oil and Gas Producing Activities"("FAS 69"). As a foreign private issuer, Enterra is permitted to comply with the disclosure requirements contained in NI 51-101 for the purposes of its U.S. regulatory filings. Unless otherwise indicated, all of the reserves and production information disclosure in this Form 20-F is in compliance with NI 51-101.

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The primary differences between the U.S. requirements and the NI 51-101 requirements are that (i)the U.S. standards require disclosure only of proved reserves, whereas NI 51-101 requires disclosure of proved and probable reserves, and (ii)the U.S. standards require that the reserves and related future net revenue be estimated under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made, whereas NI 51-101 requires disclosure of proved reserves and the related future net revenue estimated using constant prices and costs as at the last day of the financial year, and of proved and probable reserves and related future net revenue using forecast prices and costs. The definitions of proved reserves also differ, but according to the Canadian Oil and Gas Evaluation Handbook (the reference source for the definition of proved reserves under NI 51-101), differences in the estimated proved reserve quantities based on constant prices should not be material. Enterra concurs with this assessment.

In this Form 20-F, certain natural gas volumes have been converted to barrels of oil equivalent (""BOEs")on the basis of six thousand cubic feet (""Mcf")to one barrel (""bbl"). BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent equivalency at the well head.

Reserve volumes and values at December 31, 2003 are based on Enterra's interest in its total proved and probable reserves prior to royalties as defined in NI 51-101. Reserve volumes and values for previous years are based on "established" (proved plus 50% probable) reserves prior to deduction of royalties. Under those definitions, probable reserves were discounted by an arbitrary risk factor of 50% in reporting established reserves. Under NI 51-101 reserves definitions, estimates are prepared such that the full proved and probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "most likely case"). As such, the probable reserves now reported are already "risked". Overall there were no material revisions to Enterra's reserve volumes in transitioning to NI 51-101.

Enterra had its reserves evaluated by independent engineers every year. Enterra's 2003 reserves were independently evaluated as at December 31, 2003 by McDaniel and Associates Consultants Ltd. ("McDaniel") for all its properties, excluding the properties acquired in East Central Alberta. This acquisition was completed on January 30, 2004 and was evaluated by Gilbert Lausten Jung Associates Ltd. ("GLJ").

Reserve Continuity

Oil and Gas (mboe)

	Proved	Probable	Total
December 31, 2000	2,261.4	643.5	2,904.9
Discoveries and extensions	1,224.8	615.2	1,840.0
Purchases	3,277.1	981.7	4,258.8
Dispositions	(113.1)	(30.0)	(143.1)
Production	(695.5)	-	(695.5)
Revision of prior estimates	(67.7)	56.1	(11.6)
December 31, 2001	5,887.0	2,236.7	8,153.5
Discoveries and extensions	3,502.9	2,292.8	5,795.7
Dispositions	(931.9)	(441.1)	(1,373.0)
Production	(846.7)	-	(846.7)
Revision of prior estimates	(235.0)	(423.6)	(658.6)
December 31, 2002	7,376.3	3,694.6	11,070.9
Discoveries and extensions	2,800.6	860.1	3,660.7
Purchases	139.5	32.4	171.9
Dispositions	(1,707.2)	(929.6)	(2,636.8)
Production	(1,833.2)	-	(1,833.2)
Revision of prior estimates	(633.1)	(1,365.6)	(1,998.7)
December 31, 2003	6,142.9	2,291.9	8,434.8

Acquisition East Central Alberta properties	2,377.2	1,051.0	3,428.2
Total	8,520.1	3,342.9	11,863.0

Proved plus probable reserves, including the East Central Alberta acquisition, increased by 7.15% to 11.9 mmboe from 11.1 mmboe at the end of 2002. Total proved reserves increased by 15.5% to 8.5 mmboe from 7.4 mmboe at the end of 2002. Total probable reserves decreased by 9.5% to 3.3 mmboe from 3.7 mmboe at the end of 2002. The larger decrease in probable reserves is mainly due to the waterflood program at Clair which caused most of the 2002 probable reserves to be transferred to the proved category in 2003.. The new NI-51-101 policy does not affect the 2002 reserves but discounts the 2003 probable reserves by an additional 50% "risk factor". Total proved reserves represent 72% (2002   74%) of total reserves .

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Enterra s finding costs over the last 3 years are highlighted below, along with the recycle ratios for each year. The recycle ratio is a critical measure of any success in the oil and gas industry. It compares the netbacks with the finding costs. Basically, a recycle ratio of 1 is a "break even point", indicating that the enterprise earns the same amount when selling its production as it pays when finding new production.

Finding costs and recycle ratio

(in $/boe, except for capital expenditures which are in thousands)

	3-year average	2003	2002	2001
Capital expenditures ***(including East Central acquisition)***		$71,424	$35,881	$49,309
Reserves				
Proved reserves added in the year (in mboe)	13,322.0	5,317.4	3,502.8	4,501.8
Probable reserves added in the year (in mboe)	5,800.6	1,911.1	2,292.6	1,596.9
Established reserves added in the year (in mboe) (1)	17,177.8	7,228.5	4,649.1	5,300.2
Finding costs				
Proved reserves ($/boe)	$11.76	$13.43	$10.24	$10.95
Established reserves ($/boe)	$9.12	$9.88	$7.72	$9.30
Recycle ratio (netbacks divided by finding costs)				

Corporate netbacks ($/boe) (2)	$17.63	$20.08	$14.89	$14.52
Corporate recycle ratio (based on established finding costs)	1.93	2.03	1.93	1.56
Operating netbacks ($/boe) (3)	$20.28	$22.72	$18.34	$16.18
Operating recycle ratio (based on established reserves)	2.22	2.30	2.38	1.74

(1) Established reserves were proved plus 1/2 probable reserves in 2001 and 2002, and proved plus probable reserves in 2003

(2) Corporate netbacks are production revenue less royalties, operating costs, G&A and interest expense

(3) Operating netbacks are production revenue less royalties and operating costs

The estimated oil and natural gas reserves of Enterra and the associated estimated present value of estimated future net cash flows have been evaluated in a report as of December 31, 2003 prepared by McDaniel and by GLJ for the East Central Alberta properties.

The following table is based on the McDaniel and GLJ reports that show the estimated share of the remaining oil, natural gas and natural gas liquids attributable to Enterra and the estimated present value of estimated future net cash flows for these reserves, using escalating prices and costs. All estimates of present value of future net cash flows are stated after provision for capital expenditures required to generate such revenues but prior to provision for indirect costs such as general and administrative overhead, income taxes or interest expense. It should not be assumed that the estimated present values of future net cash flows are representative of the fair market value of the reserves. These recovery and reserve estimates of Enterra s interests in the described properties are estimates only; the actual reserves in the properties in which we have an interest may be more or less than those calculated. Assumptions and qualifications relating to costs, prices and other matters are summarized in the notes to the following table. The extent and character of the material information supplied by Enterra including, but not limited to, ownership, well data, production, price, revenues, operating costs and contracts were relied upon by McDaniel and GLJ in preparing the report. In the absence of such information, McDaniel and GLJ relied upon their opinion of reasonable practice in the industry. The McDaniel and GLG reports may be examined at the office of Enterra located at Suite 2600, 500- 4th Avenue S.W., Calgary, Alberta during normal business hours. All monetary amounts are expressed in Canadian dollars.

Estimated Petroleum and Natural Gas Reserves and Net Present Value

December 31, 2003

Light/ Medium Oil (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	NGL s (mmbl)	Total (mboe)	NPV 0%	NPV 10%	NPV 15%

McDaniel report								
Proved Producing	2,563.7	1,814.4	5,330.1	45.3	5,311.8	$78,467	$67,943	$63,458
Proved Non-Producing	679.8	0.0	774.0	22.2	831.0	$18,315	$15,277	$14,188
Total Proved	3,243.5	1,814.4	6,104.1	67.5	6,142.8	$96,782	$83,220	$77,646
Total Probable	1,359.0	589.7	1,926.7	22.2	2,292.0	$41,065	$28,661	$24,664
Total Proved and Probable	4,602.5	2,404.1	8,030.8	89.7	8,434.8	$137,847	$111,881	$102.310
GLJ report								
Proved Producing	1,390.9	349.9	1243.7	25.1	1,973.2	$15,354	$12,159	$11,122
Proved Non-Producing	114.2	223.2	378.2	3.5	404.0	$2,827	$1,611	$1,301
Total Proved	1,505.1	573.1	1,621.9	28.6	2,377.2	$18,181	$13,770	$12,423
Total Probable	393.5	407.0	1,347.3	25.9	1,051.0	$6,843	$4,262	$3,534
Total Proved and Probable	1,898.6	980.1	2,969.2	54.5	3,428.2	$25,024	$18,032	$15,957
Combined reports								
Proved Producing	3,954.6	2,164.3	6,573.8	70.4	7,285.0	$93,821	$80,102	$74,580
Proved Non-Producing	794.0	223.2	1,152.2	25.7	1,235.0	$21,142	$16,888	$15,489
Total Proved	4,748.6	2,387.5	7,726.0	96.1	8,520.0	$114,963	$96,990	$90.069
Total Probable	1,752.5	996.7	3,274.0	48.1	3,343.0	$47,908	$32,923	$28,198
Total Proved and Probable	6,501.1	3,384.2	11,000.0	144.2	11,863.0	$162,871	$129,913	$118,267

Historical Reserves

The following table sets out Enterra s proved oil and gas reserves at December 31, 2003, 2002 and 2001 respectively. The monetary amounts are expressed in Canadian dollars.

As at December 31	2003 (1)	2002	2001
Proved Producing Reserves:			
Oil and NGL s (mbbls)	4,447	4,443	3,431

Gas (mmcf)	5,334	10,930	7,684
Proved Reserves:			
Oil and NGL s (mbbls)	5,149	5,803	4,133
Gas (mmcf)	6,108	13,287	10,707

(1) *including East Central Alberta acquisition*

Land Holdings

At December 31 Enterra had the following land holdings

	2003	2002	2001
Developed acres (net)	13,394	28,355	22,646
Undeveloped acres (net)	42,686	51,581	58,590
Total acres (net)	56,080	79,936	81,236

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Production

The following table summarizes Enterra s working interest production during the periods indicated:

	Years ended December 31,						
	2003	2002	2001	2000	1999	1998	1997
Oil and NGL s (MBbls)	1,409	533	582	410	93	86	79
Gas (MMcf)	2,545	1,882	680	63	61	220	58
Total (MBOE)	1,834	847	695	421	100	108	85
Average Production in BOED	5,024	2,320	1,906	1,150	274	296	233

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efinitions:

"*BOEPD*" means barrels of oil equivalent produced per day.

"*MBOE*" means thousands of barrels of oil equivalent, meaning one barrel of oil or one barrel of natural gas liquids or ten mcf of natural gas.

"*MBbls*" means thousands of barrels, with respect to production of crude oil or natural gas liquids.

"*MMcf*" means millions of cubic feet, with respect to production of natural gas.

"*NGL s*" means natural gas liquids, being those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane, butanes and pentanes plus, or a combination thereof.

Drilling

Enterra s drilling history is as follows (there were no wells drilled in 1997 and 1999):

	2003	2002	2001	2000	1998
Wells drilled	Gross (Net)	Gross (Net)	Gross (Net)	Gross (Net)	Gross (Net)
Oil	31 (31.0)	25 (23.7)	9 (4.97)	9 (8.26)	0 (0.00)
Natural Gas	3 (1.1)	37 (34.0)	8 (3.78)	2 (1.27)	0 (0.00)
Injection and water disposal	6 (6.0)				
Abandoned	7 (6.4)	0 (00.0)	3 (1.84)	2 (1.14)	1 (0.13)
Total	47 (44.5)	62 (57.7)	20 (10.59)	13 (10.67)	1 (0.13)

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Notes:

(1) "Gross" wells means the number of whole wells.

(2) "Net" wells means Enterra s working interest in the gross wells.

Capital Expenditures

The following table summarizes the capital expenditures made by Enterra during the periods indicated, expressed in Canadian dollars:

(In Thousand s)	Years ended December 31,						
	2003	2002	2001	2000	1999	1998	1997
Property acquisitions (net of disposals)	($9,724)	$ 383	$52,374	$ 8,220	$ 1,879	$ 244	$ 500
Drilling (exploration and development)	28,390	21,090	5,821	6,922	341	27	50
Facilities	14,368	9,347	1,412	56	728	4	0
Miscellaneous	286	235	1,011	156	24	2	34
Total	$ 33,320	$ 30,289	$68,618	$ 15,354	$2,972	$ 277	$ 584

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Oil and Gas Wells

The following table summarizes Enterra s interest in producing and non-producing oil and gas wells as at December 31, 2003:

Property	Producing Oil Wells Gross	Producing Oil Wells Net	Producing Gas Wells Gross	Producing Gas Wells Net
Kaybob	1	0.9		
Highvale			2	0.75
Leduc	1	0.39		
Garden Plains			1	0.62
Gilby			1	0.39
Leedale			1	0.02
Lubicon	1	0.23		
Willesden Green	101	5.98	1	0.43
Timber Draw	1	0.15		
Sounding Lake East	17	16.50		

Sounding Lake West	55	27.50		
Sounding Lake North	22	6.92		
Sylvan Lake	24	22.75	1	0.32
Clair	28	28.00	5	5.00
Gordondale	1	0.50	2	1.00
Rolla			2	1.00
Swan Hills	1	0.50		
Campbell	1	0.12		
Total Wells	254	110.44	16	9.53

Employees

At December 31, 2003 we had approximately 30 employees and consultants working both in the Calgary head office and in field operations.

Office Facilities

Enterra currently leases 10,450 square feet of office space at Suite 2600, 500 - 4th Avenue S.W. in Calgary, Alberta in a lease that commenced November 1, 2001. The lease has a three-year term (expiring on November 30, 2004) and the annual rental is currently C$28.64 per square foot (including operating costs and property taxes).

Competition

The petroleum industry is highly competitive. Enterra competes with numerous other participants in the acquisition of oil and gas leases and properties, and the recruitment of employees. Any company can make acquisitions and bid on provincial leases in Alberta. Competitors include oil companies and other income trusts, many of whom have greater financial resources, staff and facilities than those of Enterra. Our ability to increase reserves in the future will depend not only on our ability to develop existing properties, but also on our ability to select and acquire suitable additional producing properties or prospects for drilling. We also compete with numerous other companies in the marketing of oil. Competitive factors in the distribution and marketing of oil include price and methods and reliability of delivery.

Government Regulation in Canada

The oil and natural gas industry is subject to extensive controls and regulations governing its operations, including land tenure, exploration, development, production, refining, transportation and marketing, imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and British Columbia, all of which should be carefully considered by investors in the Canadian oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of Enterra in a manner materially different from how they would affect other oil and gas companies of similar size operating in Western Canada. All current legislation is a matter of public record and Enterra is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing Oil and Natural Gas

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada, or NEB. Any oil export to be made pursuant to a contract of longer duration, to a maximum of 25 years, requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council. In addition, the prorationing of capacity on the interprovincial pipeline systems continues to limit oil exports.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to twenty years, in quantities of not more than 30,000 m^3/day, must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration, up to a maximum of 25 years, or a larger quantity, requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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

Provincial Royalties and Incentives

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

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

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

On December 22, 1997, the Alberta government announced that it was conducting a review of the ARTC program with the objective of setting out better-targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying for the program. Such rules will not presently preclude Enterra from being eligible for the ARTC program.

Crude oil and natural gas royalty holidays for specific wells and royalty reductions reduce the amount of Crown royalties paid by Enterra to the provincial governments. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

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Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act*, or EPEA, which came into force on September 1, 1993. The EPEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties for violations. Enterra is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. Enterra believes that it is in material compliance with applicable environmental laws and regulations. Enterra also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

Additional Information Relating to the Trust

Income Streams and Distribution Policy

A portion of the cash flows generated by the assets held, directly or indirectly, by the Trust is distributed to holders of trust units. The Trustee may, in respect of any period, declare payable to the unitholders all or any part of the net income of the Trust, less all expenses and liabilities of the Trust due and accrued and which are chargeable to the net income of the Trust.

The New Enterra Board currently intends to provide all unitholders with monthly cash distributions of approximately USD $0.10 per trust unit. However, the availability of cash flows for the payment of distributions will at all times be dependant upon a number of factors, including resource prices, production rates and reserve growth and the New Enterra Board cannot assure that cash flows will be available for distribution to unitholders in the amounts anticipated or at all. See "*Risk Factors*".

Our primary sources of cash flow is payments from New Enterra of interest on the principal amount of the Series A Notes and payments from EEC Trust of interest on the principal amount of the CT Note.

The Series A Notes

Pursuant to the Arrangement, New Enterra issued the Series A Notes to the Trust. The principal amount of the Series A Notes issued is $125,000,000. The Series A Notes are unsecured and bear interest from the date of issue at 14% per annum. Interest is payable for each month during the term on the 15th day of the month following such month.

CT Note

The CT Note is a subordinated, demand participating promissory note. The CT Note bears interest at a rate that will be re-set from time to time so as to approximate the return on the shares of New Enterra held by EEC Trust. Redemptions and returns of capital on shares of New Enterra held by EEC Trust may be required to be applied as prepayments of the principal balance of the CT Note.

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Trust Units

An unlimited number of trust units may be created and issued pursuant to the Trust Indenture. Each trust unit entitles the holder thereof to one vote at any meeting of the holders of trust units and represents an equal fractional undivided beneficial interest in any distribution from the Trust (whether of net income, net realized capital gains or other amounts) and in any net assets of the Trust in the event of termination or winding up of the Trust. All trust units rank among themselves equally and rateably without discrimination, preference or priority. Each trust unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require the Trust to redeem any or all of the trust units held by such holder (see "*Redemption Right*") and to one vote at all meetings of unitholders for each trust unit held. In addition, in certain circumstances unitholders will have the right to instruct the trustees of EEC Trust with respect to the voting of shares of New Enterra held by EEC Trust at meetings of holders of shares of New Enterra. See "*Meetings of Unitholders*" and "*Exercise of Voting Rights*".

The trust units do not represent a traditional investment and should not be viewed by investors as "shares" in either New Enterra, or the Trust. As holders of trust units in the Trust, unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions.

The price per trust unit is a function of anticipated distributable income generated by New Enterra and the ability of New Enterra to effect long term growth in the value of the Trust. The market price of the trust units is sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and the ability of New Enterra to acquire additional assets. Changes in market conditions may adversely affect the trading price of the trust units.

The trust units are not "deposits" within the meaning of the Canada Deposit Insurance Corporation Act (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

Special Voting Rights

The Trust Indenture allows for the creation of Special Voting Rights which will enable the Trust to provide voting rights to holders of Exchangeable Shares and, in the future, to holders of other exchangeable shares that may be issued by New Enterra or other subsidiaries of the Trust in connection with other exchangeable share transactions.

Holders of Special Voting Rights are not be entitled to any distributions of any nature whatsoever from the Trust and each holder shall be entitled to attend at meetings of unitholders and, subject to the terms of the instrument creating the Special Voting Rights, is entitled to that number of votes equal to the number of votes attached to the trust units for which the Special Voting Rights held by such holder are exchangeable, exercisable or convertible. Holders of Special Voting Rights are also be entitled to receive all notices, communications or other documentation required to be given or otherwise sent to holders of trust units. Except for the right to attend and vote at meetings of unitholders and receive notices, communications and other documentation sent to unitholders, the Special Voting Rights do not confer upon the holders thereof any other rights.

Under the terms of the Voting and Exchange Trust Agreement, the Trust has issued a Special Voting Right to the Voting and Exchange Trust Agreement Trustee for the benefit of every person who received Exchangeable Shares pursuant to the Arrangement.

Unitholder Limited Liability

The Trust Indenture provides that no unitholder, in its capacity as such, shall incur or be subject to any liability in contract or in tort in connection with the Trust or its obligations or affairs and, in the event that a court determines unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust's assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each unitholder from any costs, damages, liabilities, expenses, charges or losses suffered by a unitholder from or arising as a result of such unitholder not having such limited liability.

The Trust Indenture provides that all contracts signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon unitholders personally. Notwithstanding the terms of the Trust Indenture, unitholders may not be protected from liabilities of the Trust to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against the Trust (to the extent that claims are not satisfied by the Trust) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to unitholders of this nature arising is considered unlikely in view of the fact that the sole activity of the Trust is to hold securities, and all of the business operations are carried on by New Enterra, directly or indirectly.

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The activities of the Trust, the EEC Trust, New Enterra and the Partnership is conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability to the unitholders for claims against the Trust including by obtaining appropriate insurance, where available, for the operations of New Enterra and having contracts signed by or on behalf of the Trust include a provision that such obligations are not binding upon unitholders personally.

Redemption Right

Trust units are redeemable at any time on demand by the holders thereof upon delivery to the transfer agent of the Trust of the certificate or certificates representing such trust units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem trust units by the transfer agent, the holder thereof shall only be entitled to receive a price per trust unit (the "Market Redemption Price") equal to the lesser of: (i) 90% of the "market price" of the trust units on the principal market on which the trust units are quoted for trading during the 10 trading day period commencing immediately after the date on which the trust units are tendered to the Trust for redemption; and (ii) the closing market price on the principal market on which the trust units are quoted for trading on the date that the trust units are so tendered for redemption. Where more than one market exists for the trust units, the principal market shall mean the market on which the trust units experience the greatest volume of trading activity on the date or for the period in question, as applicable.

For the purposes of this calculation, "market price" is an amount equal to the simple average of the closing price of the trust units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the trust units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the trust units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the trust units for each day that there was trading, if the market provides only the highest and lowest prices of trust units traded on a particular day. The closing market price is: an amount equal to the closing price of the trust units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the trust units if there was trading and the exchange or other market provides only the highest and lowest prices of trust units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The aggregate Market Redemption Price payable by the Trust in respect of any trust units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. The entitlement of unitholders to receive cash upon the redemption of their trust units is subject to the limitation that the total amount payable by the Trust in respect of such trust units and all other trust units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed $100,000; provided that New Enterra may, in its sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by the Trust in respect of trust units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by the Trust distributing Series A Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the trust units tendered for redemption, and (ii) secondly, to the extent that the Trust does not hold Series A Notes having a sufficient principal amount outstanding to effect such payment, by the Trust issuing its own promissory notes to the unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall (herein referred to as "Redemption Notes"). Notwithstanding the foregoing, the distribution of any Series A Notes and the issuance of any Redemption Notes shall be conditional upon the receipt of all necessary regulatory approvals and the making of all necessary governmental registrations, declarations and filings, including, without limitation, any required registration of the Series A Notes or Redemption Notes, as applicable, to be distributed or issued in respect of the payment of the Market Redemption Price, and any required qualification of the Trust Indenture relating to such Series A Notes or Redemption Notes, under the securities laws of the United States.

If at the time trust units are tendered for redemption by a unitholder, (i) the outstanding trust units are not listed for trading on the TSX or Nasdaq and are not traded or quoted on any other stock exchange or market which New Enterra considers, in its sole discretion, provides representative fair market value price for the trust units, or (ii) trading of the outstanding trust units is suspended or halted on any stock exchange on which the trust units are listed for trading or, if not so listed, on any market on which the trust units are quoted for trading, on the date such trust units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such trust units were tendered for redemption then such unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per trust unit (the "Appraised Redemption Price") equal to 90% of the fair market value thereof as determined by New Enterra as at the date on which such trust units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of trust units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Series A Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of trust units to dispose of their trust units. Series A Notes or Redemption Notes which may be distributed in specie to unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Series A Notes or Redemption Notes. Series A Notes or Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Meetings of Unitholders

The Trust Indenture provides that meetings of unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of the auditors of the Trust, the approval of amendments to the Trust Indenture (except as described under "Amendments to the Trust Indenture"), the sale of the property of the Trust as an entirety or substantially as an entirety, and the commencement of winding up the affairs of the Trust.

A meeting of unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned in writing by (i) New Enterra or (ii) the holders of trust units and Special Voting Rights holding in aggregate not less than 5% of the votes entitled to be voted at a meeting of unitholders. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of unitholders either in person or by proxy and a proxyholder need not be a unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least 5% of the votes attaching to all outstanding trust units shall constitute a quorum for the transaction of business at all such meetings. For the purposes of determining such quorum, the holders of any issued Special Voting Rights who are present at the meeting shall be regarded as representing outstanding trust units equivalent in number to the votes attaching to such Special Voting Rights.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of unitholders in accordance with the requirements of applicable laws.

Voting Of EEC trust units

There will be a meeting of the holders of EEC trust units immediately following each meeting of unitholders for the purpose of directing the Trustee as to the manner in which the Trustee shall vote the EEC trust units held by the Trust in respect of those matters voted on at such meeting of unitholders. Any resolution passed by unitholders pertaining to the manner in which EEC trust units held by the Trust are to be voted by the Trustee in respect of a particular matter which is to be put forth to the holders of EEC trust units for vote at a contemplated meeting (including by written resolution) of holders of EEC trust units, shall be deemed to be a direction to the Trustee in respect of the EEC trust units held by the Trust to, as applicable, either vote such EEC trust units in favour of or in opposition to, or to vote or with-hold from voting in respect of such matter in equal proportions to the votes cast by unitholders in respect of the matter, and the Trustee is obligated to vote, in respect of such matter if put forth to the holders of EEC trust units at a meeting of such holders, the EEC trust units held by the Trust in accordance with such direction.

Exercise of Voting Rights

The Trustee is prohibited from authorizing or approving:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets owned, directly or indirectly, by the Trust, except in conjunction with an internal reorganization of the direct or indirect assets of the Trust, as a result of which the Trust has substantially the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving the Trust and any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above; or

(c) the winding up, liquidation or dissolution of the Trust prior to the end of the term of the Trust except in conjunction with an internal reorganization as referred to in paragraph (a) above;

without the prior approval of the unitholders by Special Resolution at a meeting of unitholders called for that purpose.

In addition, the Trustee is prohibited from authorizing EEC Trust to vote any shares of New Enterra in respect of:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets owned, directly or indirectly, by Enterra, the Trust or the Partnership, except in conjunction with an internal reorganization of the direct or indirect assets of New Enterra, EEC Trust or the Partnership, as the case may be, as a result of which EEC Trust has substantially the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any merger, amalgamation, arrangement, reorganization, recapitalization, business combination or similar transaction involving New Enterra, EEC Trust or the Partnership and any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(c) the winding up, liquidation or dissolution of New Enterra, EEC Trust or the Partnership prior to the end of the term of EEC Trust, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(d) any amendment to the articles of New Enterra to increase or decrease the minimum or maximum number of directors;

(e) any material amendments to the articles of New Enterra to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of New Enterra's shares in a manner which may be prejudicial to EEC Trust; or

(f) any material amendment to the CT Indenture or the Partnership Agreement which may be prejudicial to EEC Trust;

without the prior approval of the unitholders by Special Resolution at a meeting of unitholders called for that purpose.

Finally, the Trustee is prohibited from authorizing EEC Trust to vote any shares of New Enterra with respect to any matter which under applicable law (including policies of Canadian securities commissions) or applicable stock exchange rules would require the approval of the holders of shares of New Enterra by ordinary resolution or special resolution, without the prior approval of the unitholders by Ordinary Resolution or Special Resolution, as the case may be.

Trustee

Olympia Trust Company is the initial trustee of the Trust. The Trustee is responsible for, among other things, accepting subscriptions for trust units and issuing trust units pursuant thereto, maintaining the books and records of the Trust and providing timely reports to holders of trust units. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

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The initial term of the Trustee's appointment is until the third annual meeting of unitholders. The unitholders shall, at the third annual meeting of unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, the unitholders shall reappoint or appoint a successor to the Trustee at the annual meeting of unitholders three years following the reappointment or appointment of the successor to the Trustee. The Trustee may also be removed by Special Resolution of the unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Delegation of Authority, Administration and Trust Governance

The New Enterra Board has generally been delegated the significant management decisions of the Trust. In particular, the Trustee has delegated to New Enterra responsibility for any and all matters relating to the following: (i) an offering of securities of the Trust; (ii) ensuring compliance with all applicable laws, including in relation to an offering of securities of the Trust; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of the material contracts of the Trust; (v) all matters concerning any underwriting or agency agreement providing for the sale of trust units or rights to trust units; (vi) all matters relating to the redemption of trust units; (vii) all matters relating to the voting rights on any instruments held by the Trust, other than the EEC trust units; and (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Liability of The Trustee

The Trustee, its directors, officers, employees, shareholders and agents is not be liable to any unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to the Trust or the property of the Trust, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, any action taken or not taken in good faith in reliance on any documents that are, prima facie, properly executed, any depreciation of, or loss to, the property of the Trust incurred by reason of the sale of any asset, any inaccuracy in any evaluation provided by any other appropriately qualified person, any reliance on any such evaluation, any action or failure to act of New Enterra, or any other person to whom the Trustee has, with the consent of New Enterra, delegated any of its duties hereunder, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by New Enterra to perform its duties under or delegated to it under the Trust Indenture or any other contract), unless such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees or shareholders. If the Trustee has retained an appropriate expert, adviser or legal counsel with respect to any matter connected with its duties under the Trust Indenture, the Trustee may act or refuse to act based on the advice of such expert, adviser or legal counsel, and the Trustee shall not be liable for and shall be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, adviser or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and shall be conclusively deemed to be acting as Trustee of the assets of the Trust and shall not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to the Trust or the property of the Trust. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to The Trust Indenture

The Trust Indenture may be amended or altered from time to time by special resolution of the unitholders. The Trustee may, without the approval of any of the unitholders, amend the Trust Indenture for the purpose of:

(a) ensuring the Trust's continuing compliance with applicable laws or requirements of any governmental agency or authority;

(b) ensuring that the Trust will satisfy the provisions of each of subsections 108(2) and 132(6) and paragraph 132(8)(a) of the Tax Act as from time to time amended or replaced;

(c) providing for and ensuring (i) the allocation of items of income, gain, loss, deduction and credit in respect of the Trust for United States federal income tax purposes; (ii) the filing of income tax returns necessary or desirable for the purposes of United States federal income tax; or (iii) compliance by the Trust with any other applicable provisions of United States federal income tax law;

(d) ensuring that such additional protection is provided for the interests of unitholders as the Trustee may consider expedient;

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(e) removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture and any other agreement of the Trust or any offering document pursuant to which securities of the Trust are issued with respect to the Trust, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of the unitholders are not prejudiced thereby;

(f) curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of the unitholders are not prejudiced thereby; and

(g) changing the situs of or the laws governing the Trust which, in the opinion of the Trustee, is desirable in order to provide unitholders with the benefit of any legislation limiting their liability.

Termination of the Trust

Unitholders may vote to terminate the Trust at any meeting of unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the outstanding trust units; (b) a quorum of 50% of the issued and outstanding trust units is present in person or by proxy; and (c) the termination must be approved by special resolution of unitholders.

Unless the Trust is earlier terminated or extended by vote of the unitholders, the Trust shall continue in full force and effect for a period which shall end twenty-one years after the date of death of the last surviving issue of Her Majesty, Queen Elizabeth II. In the event that the Trust is wound up, the Trustee will sell and convert into money the property of the Trust in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the property of the Trust in accordance with any applicable laws or requirements of any governmental agency or authority, and shall in all respects act in accordance with the directions, if any, of the unitholders in respect of termination authorized pursuant to the special resolution of the unitholders authorizing the termination of the Trust. After paying, retiring or discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Trust and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of the property of the Trust among the unitholders in accordance with their pro rata interests.

Reporting to Unitholders

The financial statements of the Trust are audited annually by an independent recognized firm of chartered accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, will be mailed by the Trustee to unitholders and the unaudited interim financial statements of the Trust will be mailed to unitholders within the periods prescribed by securities legislation. The year end of the Trust shall be December 31. The Trust is subject to the continuous disclosure obligations under all applicable securities legislation.

The Trust is subject to the reporting requirements of the 1934 Act applicable to foreign private issuers, and in connection therewith will file or submit reports, including annual reports and other information with the U.S. Securities and Exchange Commission (the "SEC"). Such reports and other information can be inspected and copied at the public reference facilities maintained by the SEC at 450 Fifth Street, N.W., Room 1024, Judiciary Plaza, Washington, D.C. The Trust's SEC filings and submissions will also be available to the public on the SEC's web site at http://www.sec.gov.

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ITEM 5. Operating and Financial Review and Prospects

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

AND RESULTS OF OPERATIONS

The following management s discussion and analysis of Enterra Energy Trust ("Enterra or the Trust") is as of April 16, 2004 and should be read in conjunction with the audited consolidated financial statements of the Trust for the years ended December 31, 2003 and 2002, together with accompanying notes, which have been prepared in accordance with Canadian generally accepted accounting principles. The significant differences to generally accepted accounting principles of the United States of America are as set out in note 17. Discussion with regard to the Trust s 2004 outlook is based on currently available information. All amounts are stated in Canadian dollars except where otherwise indicated. Natural gas volumes have been converted to a crude oil equivalent using a ratio of 6 mcf to 1 bbl of oil.

Cash flow, expressed before changes in non-cash working capital, is used by Enterra to measure and evaluate operating performance and liquidity. Earnings from operations, which is calculated before income taxes and before gains or losses on disposal of assets, is used by Enterrra to measure and evaluate operating performance. Cash flow and earnings from operations do not have any standardized meaning prescribed by the Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable with the calculation of similar measures for other companies.

It is management s view, based on its communications with investors during events like conference calls, webcasts or road shows, that these non-GAAP measures are most relevant to our investors and unitholders, especially since Enterra s conversion to an oil and gas income trust. Earnings from operations, because it excludes one-time non-recurring events, can provide investors with an undistorted frame of reference when comparing performance from year to year or quarter to quarter. Cash flow from operations is also extremely relevant to investors because it is the starting point for setting the monthly distribution level.

Both cash flow from operations and earnings from operations are reconciled to GAAP earnings in tables included in the management discussion and analysis section.

Special Note Regarding Forward-Looking Statements

This annual report includes forward-looking statements. All statements other than statements of historical facts contained in this annual report, including statements regarding our future financial position, business strategy and plans and objectives of management for future operations, are forward-looking statements. The words "believe," "may," "will," "estimate," "continue," "anticipate," "intend," "should," "plan," "expect" and similar expressions, as they relate to us, are intended to identify forward-looking statements. We have based these forward-looking statements largely on our current expectations and projections about future events and financial trends that we believe may affect our financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions described in "Risk Factors" and elsewhere in this annual report.

Other sections of this annual report may include additional factors which could adversely affect our business and financial performance. Moreover, we operate in a very competitive and rapidly changing environment. New risk factors emerge from time to time and it is not possible for our management to predict all risk factors, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

We undertake no obligation to update publicly or revise any forward-looking statements. You should not rely upon forward-looking statements as predictions of future events or performance. We cannot assure you that the events and circumstances reflected in the forward-looking statements will be achieved or occur. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements.

Critical Accounting Policies

The Company follows the full cost method of accounting for oil and natural gas properties and equipment whereby we capitalize all costs relating to its acquisition of, exploration for and development of oil and natural gas reserves. Enterra s consolidated financial condition and results of operations are sensitive to, and may be adversely affected by, a number of subjective or complex judgments relating to methods, assumptions or estimates required under the full cost method of accounting concerning the effect of matters that are inherently uncertain. For example:

(i) Capitalized costs under the full cost method are generally depleted and depreciated using the unit-of-production method, based on estimated proved oil and gas reserves as determined by independent engineers. In addition, capital costs are also restricted from exceeding the sum of the estimated future net revenues of those properties, plus the cost or estimated fair value of unproved properties less estimated future abandonment and site restoration costs, general administrative expenses, financing costs and income taxes (the "ceiling test"). Should this comparison indicate an excess carrying value, a write-down would be recorded. To economically evaluate the Enterra s proved oil and natural gas reserves, these independent engineers must necessarily make a number of assumptions, estimates and judgments that they believe to be reasonable based upon their expertise and professional and CICA and SEC guidelines. Were the independent engineers to use differing assumptions, estimates and judgments, then Enterra s consolidated financial condition and results of operations would be affected. For example, Enterra would have lower revenues and net profits (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in lower reserve estimates, since our depletion and depreciation rate would then be higher and it might also result in a write-down under the ceiling test. Similarly, Enterra would have higher revenues and net profits (or lower net losses) in the event the revised assumptions, estimates and judgments resulted in higher reserve estimates.

(ii) Enterra s management also periodically assesses the carrying values of unproved properties to ascertain whether any impairment in value has occurred. This assessment typically includes a determination of the anticipated future net cash flows based upon reserve potential and independent appraisal where warranted. Impairment is recorded if this assessment indicates the future potential net cash flows are less than the capitalized costs. Were Enterra s management to use differing assumptions, estimates and judgments, then Enterra s consolidated financial condition and results of operations would be affected. For example, Enterra would have lower net profits (or higher net losses) in the event the revised assumptions, estimates and judgments resulted in increased impairment expense.

(iii) Estimated future restoration costs are provided for using the unit of production method based on estimated gross proved reserves. Costs are estimated by our engineers based on current regulations, costs, technology and industry standards. The annual charge is recorded as a provision for future site restoration and abandonment costs. Removal and site restoration expenditures are charged to the accumulated provision as incurred.

Results of Operations 2003 compared to 2002

Overview

Enterra managed to achieve record revenue, cash flow and earnings in 2003 while converting itself to an oil and gas income trust during the fourth quarter. Cash flow from operations, excluding the one-time re-organization costs of $5.8 million, was in excess of $36 million for the year or $1.92 on a per unit basis. As a trust, Enterra established its initial monthly distribution level at US$0.10 per unit. The first distribution was paid on January 15, 2004 for the month of December 2003. Enterra drilled 47 wells in 2003, including 20 wells at Clair and 19 wells at Sylvan Lake. The two projects represented almost 60% of Enterra s 2003 capital expenditures. The 2003 drilling program resulted in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate.

Summarized financial and operational data ***(in Thousand s except for volumes and per unit/ share amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Exit production rate (boe per day)	6,460	5,335	+ 21%	6,460	5,335	+ 21%
Average production revenue	$15,598	$10,060	+ 55%	$72,097	$25,746	+180%
Average production volumes (boe per day)	5,206	3,221	+ 62%	5,024	2,320	+117%
Cash flow from operations [(1) (3)]	$ 7,467	$ 4,851	+ 54%	$36,455	$11,950	+205%
Cash flow from operations per unit/share [(1) (3)]	$ 0.37	$ 0.26	+ 40%	$ 1.92	$ 0.65	+195%
Earnings from operations [(2) (3)]	$1,019	$ 1,108	- 8%	$12,835	$ 2,909	+341%
Earnings from operations per unit/share [(2) (3)]	$ 0.05	$ 0.06	- 17%	$ 0.68	$ 0.16	+326%
Average number of units outstanding *(after giving effect to trust conversion)*	20,205	18,337	+ 10%	18,954	18,309	+ 4%
Average price per bbl of oil	$ 31.78	$ 34.93	- 9%	$ 39.12	$ 33.86	+ 16%
Average price per mcf of natural gas	$ 5.91	$ 5.34	+ 11%	$ 6.65	$ 4.08	+ 63%
Operating costs per boe	$ 6.19	$ 7.88	- 21%	$ 6.96	$ 7.11	- 2%
General and administrative expenses per boe *(cash portion)*	$ 1.59	$ 1.71	- 7%	$ 1.69	$ 1.99	- 15%

(1) *Excluding re-organization costs of $5.8 million in year and Q4, 2003*

(2) *Excluding income taxes, re-organization costs of $5.8 million in 2003 and $3.1 million gain on redemption of preferred shares in 2002*

(3) *Both cash flow from operations and earnings from operations are non-GAAP measures. It is management s view that this information is relevant for investors in order to compare 2003 with 2002 without the impact of one-time non-recurring events. Both cash flow from*

operations and earnings from operations are reconciled to GAAP earnings in the earnings and cash flow sections of the management discussion and analysis.

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QUARTERLY INFORMATION

Quarterly information ***(In Thousand s, except per unit/ share data)***

	Q1 2003	Q1 2002	Q2 2003	Q2 2002	Q3 2003	Q3 2002	Q4 2003	Q4 2002
Revenue	$ 22,002	$ 5,598	$ 18,484	$ 5,051	$ 16,012	$ 5,036	$ 15,598	$ 10,060
Income from operations	$ 7,192	$ 326	$ 2,699	$ 620	$ 1,924	$ 854	$ 1,019	$ 1, 108
Per unit/share, basic	$ 0.39	$ 0.02	$ 0.15	$ 0.03	$ 0.10	$ 0.04	$ 0.04	$ 0.06
Per unit/share, diluted	$ 0.37	$ 0.02	$ 0.14	$ 0.03	$ 0.09	$ 0.04	$ 0.08	$ 0.05
Net earnings	$ 4,186	$ 3,150	$ 4,965	$ 398	$ 956	$ 714	$ (5,104)	$ 715
Per unit/share, basic	$ 0.23	$ 0.17	$ 0.27	$ 0.02	$ 0.05	$ 0.04	$ (0.28)	$ 0.04
Per unit/share, diluted	$ 0.21	$ 0.17	$ 0.25	$ 0.02	$ 0.05	$ 0.04	$ (0.25)	$ 0.03

3 YEAR SUMMARY

Summarized financial and operational data ***(in Thousand s except for volumes and per unit/share amounts)***

	Year 2003	Year 2002	Year 2001
Revenue	$72,097	$25,746	$20,264
Cash flow from operations (1) (4)	$36,455	$11,950	$ 9,810
Cash flow from operations per unit/share basic(1)	$ 1.92	$ 0.65	$ 0.70
Cash flow from operations per unit/share diluted(1)	$ 1.92	$ 0.63	$ 0.70

Earnings from operations [2] [4]	$12,835	$ 2,909	$ 3,228
Earnings from operations per unit/share - basic [2]	$ 0.68	$ 0.16	$ 0.23
Earnings from operations per unit/share - diluted [2]	$ 0.68	$ 0.15	$ 0.23
Net earnings	$ 5,004	$ 4,977	$ 1,617
Net earnings per unit/share - basic	$ 0.26	$ 0.27	$ 0.12
Net earnings per unit/share - diluted	$ 0.26	$ 0.27	$ 0.12
Average number of units outstanding *(after giving effect to trust conversion)*	18,954	18,309	13,985
Total assets	$ 116,230	$ 102,717	$ 80,063
Total long-term debt *(including bank debt and capital leases)*	$ 38,128	$ 29,358	$18,409
Distribution per unit [3]	US$ 0.10	N/A	N/A

[1] Excluding re-organization costs of $5.8 million in year and Q4, 2003

[2] Excluding income taxes, re-organization costs of $5.8 million in 2003,$3.1 million gain on redemption of preferred shares in 2002 and $929,037 in restructuring charges in 2001

[3] Only one distribution for the month of December 2003, paid on January 15, 2004 for US$0.10 per unit

4)

Both cash flow from operations and earnings from operations are non-GAAP measures. It is management s view that this information is relevant for investors in order to compare 2003, 2002 and 2001 without the impact of one-time non-recurring events. Both cash flow from operations and earnings from operations are reconciled to GAAP earnings in the earnings and cash flow sections of the management discussion and analysis.

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PRODUCTION INCOME

Production income increased by 180% in 2003 from $25.7 million to $72.1 million. Approximately 30% of this increase was due to the higher commodity prices in effect during 2003 and 70% was due to the higher production volumes in 2003.

Production income increased by 55% in Q4, 2003 from $10.1 million to $15.6 million. All of this increase is due to higher production, as pricing actually decreased slightly in Q4, 2003 by 4%.

Enterra drilled 47 wells in 2003, including 20 wells at Clair and 19 wells at Sylvan Lake. The two projects represented almost 60% of Enterra s 2003 capital expenditures. The 2003 drilling program resulted in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate. Enterra s production in 2003 averaged 5,024 boe/day, consisting of 3,862 bbls/day of oil and 6,972 mcf/day of natural gas, for a mix of 77% oil and 23% natural gas.

Enterra s production in Q4 of 2003 averaged 5,206 boe/day, consisting of 4,110 bbls/day of oil and 6,572 mcf/day of natural gas, for a mix of 79% oil and 21% natural gas. Enterra s production in Q4 of 2002 averaged 3,221 boe/day, consisting of 2,142 bbls/day of oil and 6,477 mcf/day of natural gas, for a mix of 67% oil and 33% natural gas. Enterra drilled 15 wells in Q4, 2003 compared to 54 wells in Q4, 2002.

Enterra exited 2003 at a rate of 6,460 boe/day, consisting of 4,890 bbls/day of oil and 9,420 mcf/day of natural gas, for a mix of 76% oil and 24% natural gas. This represents a 21% increase over the 2002 exit rate of 5,335 boe/day.

Production income ***(in Thousand s except for volumes and pricing)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Crude oil and natural gas liquids	$12,022	$6,878	+ 75%	$ 55,185	$ 18,075	+ 205%
Natural gas	3,576	3,182	+ 12%	16,912	7,671	+ 120%
Total production income	$15,598	$10,060	+ 55%	$ 72,097	$ 25,746	+ 180%
Volumes						
Average oil production (in bbls/day)	4,110	2,142	+ 92%	3,862	1,460	+ 164%
Average gas production (in mcf/day)	6,572	6,477	+ 1%	6,972	5,157	+ 35%
Average total production (in boe/day)	5,206	3,221	+ 62%	5,024	2,320	+ 117%
Exit oil production (in bbls/day)	4,890	4,205	+ 16%	4,890	4,205	+ 16%
Exit gas production (in mcf/day)	9,420	6,780	+ 39%	9,420	6,780	+ 39%
Exit total production (in boe/day)	6,460	5,335	+ 21%	6,460	5,335	+ 21%
Commodity Pricing Benchmarks						
West Texas Intermediate (US$/bbl)	31.18	28.29	+ 10%	31.10	26.13	+ 19%

Exchange rate (US$)	0.7600	0.6372	+ 19%	0.7164	0.6371	+ 12%
Edmonton Par ($/bbl)	39.85	43.18	- 8%	43.39	40.20	+ 8%
NYMEX (US$/mmbtu)	5.44	4.33	+ 26%	5.49	3.36	+ 63%
Alberta Spot ($/mcf)	5.69	5.52	+ 3%	6.50	3.96	+ 64%
Commodity Prices received by Enterra						
Average price received per bbl of oil	31.78	34.93	- 9%	39.12	33.86	+ 16%
Average price received per mcf of natural gas	5.91	5.34	+ 11%	6.65	4.08	+ 63%

PRODUCTION EXPENSES

Production expenses increased by 112% in 2003 and by 27% in Q4 compared to their respective periods in 2002. These increases are consistent with the higher production levels in 2003. Both as a percentage of revenue and on a per boe basis, Enterra reduced its operating costs in 2003, mainly due to operating efficiencies gained at Clair in the fourth quarter of 2003 by implementing a sales line which eliminated trucking and terminal fees for that area. This is why the production expenses per boe were 21% lower in Q4, 2003 compared to 2002 ($6.19 per boe in 2003 compared to $7.88 per boe in 2002)

Production expenses ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Production expenses	$ 2,966	$ 2,335	+ 27%	$ 12,762	$ 6,018	+ 112%
As a percentage of production revenue	19%	23%	- 17%	18%	23%	- 22%
Production expenses per boe	$ 6.19	$ 7.88	- 21%	$ 6.96	$ 7.11	- 2%

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties, increased by 320% in 2003 and by 128% in Q4 compared to their respective periods in 2002. These increases are the result of both the increased production in 2003 and the higher commodity prices in effect during the year. Most royalties are calculated on a sliding scale based on commodity prices. As commodity prices increase, so do the royalty rates. Conversely, the Alberta Royalty Tax Credit is reduced as commodity prices increase. Since royalties are not calculated by reference to any hedging position entered into by Enterra, any hedging loss will result in a higher royalty expense as a percentage of production revenue. These factors were the reason for the increase (50% for the year and 47% for Q4) in royalty expense both as a percentage of production revenue and on a per boe basis.

Royalties ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Royalties	$ 3,916	$ 1,721	+ 128%	$ 17,656	$ 4,203	+ 320%
As a percentage of production revenue	25%	17%	+ 47%	24%	16%	+ 50%
Royalties per boe	$ 8.18	$ 5.81	+ 41%	$ 9.63	$ 4.96	+ 94%

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses increased by 84% in 2003 and 50% in Q4 compared to their respective periods in 2002. Approximately 80% of the increase in 2003 is the result of additional staffing requirements. Other areas which incurred higher expenses were marketing and travel costs, insurance premiums, and higher regulatory compliance costs both for the Canadian and U.S. exchanges. Capitalized general and administrative costs were consistent in both years, $1,787,000 (or 32% of total general and administrative expenses) in 2003 and $1,450,900 (or 39% of total general and administrative expenses) in 2002. The non-cash portion of general and administrative expenses in 2003 relate to the value assigned to 200,000 warrants (see Note 9(h) of the Financial Statements for details).

General and administrative expenses ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
General and administrative expenses cash portion	$ 760	$ 505	+ 50%	$ 3,103	$ 1,683	+ 84%
General and administrative expenses non-cash portion	-	-		$ 281	-	
As a percentage of production revenue (cash portion)	5%	5%	0%	4%	7%	- 43%
General and administrative expenses per boe (cash portion)	$ 1.59	$ 1.71	- 7%	$ 1.69	$ 1.99	- 15%

INTEREST EXPENSE

Interest expense increased by 42% in 2003 and decreased by 23% in Q4 compared to their respective periods in 2002. The 2003 increase is due to the higher average outstanding loan balances during the year. The decrease in Q4 is due to the fact that, on average, the Q4 loan balances were higher in 2002 because of the higher drilling activity in Q4, 2002 compared to Q4, 2003 (54 wells were drilled in Q4, 2002 compared to 15 wells drilled in Q4, 2003).

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Interest expense ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Long-term debt, including bank debt at end of period	$ 38,128	$ 29,358	+ 30%	$ 38,128	$ 29,358	+ 30%
Interest expense	$ 410	$ 531	- 23%	$ 1,749	$ 1,236	+ 42%
As a percentage of production revenue	3%	5%	- 40%	2%	5%	- 60%
Interest expense per boe	$ 1.79	$ 0.86	- 52%	$ 0.95	$ 1.46	- 35%

DEPLETION AND DEPRECIATION

Depletion and depreciation expense increased by 152% in 2003 and by 80% in Q4 compared to their respective periods in 2002. The increase is due to a higher production rate in the year and Q4, 2003. The depletable base was consistent in both years as the capital expenditures, net of proceeds on disposal of properties, were $33 million in 2003 and $ 30 million in 2002.

Depletion and depreciation ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Depletion and depreciation expense	$ 6,236	$ 3,468	+ 80%	$ 23,447	$ 9,306	+ 152%
As a percentage of production revenue	40%	34%	+ 18%	33%	36%	- 8%

Depletion and depreciation expense per boe	$ 13.02	$ 11.70	+ 11%	$ 12.79	$ 10.99	+ 16%

INCOME AND CAPITAL TAXES

The combined federal and provincial income taxes decreased in 2003 to 40.75% from 42.12% in 2002. The actual tax provision recorded on the financial statements is at much lower rates in both 2003 and 2002 (29.32% in 2003 and 17.32% in 2002). The rate was very low in 2002 mainly because of the $3.1 million gain on redemption of preferred shares which was not a taxable gain for tax purposes, resulting in a lower tax provision in that year. The rate was also lower in 2003 mainly due to changes in the timing differences related to the Crown royalties and the resource allowance calculation, and to differences related to the Trust distributions, which are deductible in part for tax purposes but are not deducted to arrive at net earnings.

Income and capital taxes (*in Thousand s except for percentages)*

	Year 2003	Year 2002	*Change*
Income tax expense	$ 2,075	$ 1,043	+ 99%
Combined federal and provincial income tax rate	40.75%	42.12%	- 3%
Actual tax rate as a percentage of net earnings	29.32%	17.32%	+ 71%
Estimated tax pools at December 31			
Canadian oil and gas property expense (COGPE)	$ 11,268	$ 20,148	
Canadian exploration expense (CEE)	$ 8,832	$ 9,870	
Canadian development expense (CDE)	$ 21,297	$ 4,708	
Undepreciated capital cost (UCC)	$ 23,247	$ 27,109	
Other	$ 1,740	$ 2,331	
	$ 66,384	$ 64,166	+ 3%

EARNINGS

Both earnings from operations and net earnings are presented below in order to show the impact of one-time events which occurred in both years. Earnings were higher in 2002 because of the impact of a $3.1 million gain on redemption of preferred shares. The opposite occurred in 2003 as earnings were reduced by the re-organization costs related to the conversion to a trust structure in the fourth quarter of 2003.

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Enterra s earnings from operations increased by 341% in 2003 and decreased by 8% in Q4 compared to their respective periods in 2002. The large 2003 increase was caused by increased production (up 117% for the year), higher prices (higher on average by 29% during 2003) and, except for royalties, lower expenses as a percentage of revenue in 2003. The results were similar on a per unit basis, $0.68 per unit in 2003 compared to $0.16 per unit in 2002, for with a 326% increase.

Q4 s earnings from operations were almost identical in each year, despite the higher production in 2003. This is due mainly to lower royalties and lower depletion in 2002. The large loss in Q4 of 2003 is the direct results of the $5.8 million in costs related to the trust conversion.

As mentioned earlier, it is management s view that earnings from operations is a good measure of performance and an appropriate benchmark when comparing results from year to year or quarter to quarter because it excludes one-time non-recurring events which may otherwise distort the financial results. Earnings from operations is a non-GAAP measure, reconciled with GAAP net earnings in the table below:

Earnings *(in Thousand s except for per unit/share amounts)*

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Earnings from operations	$ 1,020	$ 1,108	- 8%	$ 12,835	$ 2,909	+ 341%
Deduct re-organization costs	(5,756)	-		(5,756)	-	
Add back gain on redemption of preferred shares	-	-		-	3,111	
Earnings (loss) before income taxes	$(4,736)	$ 1,108	N/A	$ 7,079	$ 6,020	+ 18%
Deduct income taxes	(367)	(393)		(2,075)	(1,043)	
Net earnings (loss)	$(5,103)	$ 715	N/A	$ 5,004	$ 4,977	+ 1%
Earnings from operations as a percentage of revenue	7%	11%	- 36%	18%	11%	+ 64%
Earnings from operations on a per boe basis	$ 2.13	$ 3.74	- 43%	$ 7.00	$ 3.44	+ 103%

Per unit/share information

Earnings from operations per unit/share	$ 0.05	$ 0.06	- 17%	$ 0.68	$ 0.16	+ 326%
Net earnings (loss) per unit/share	$ (0.25)	$ 0.04	N/A	$ 0.26	$ 0.27	0%
Average number of units/share outstanding	20,205	18,336	+ 10%	18,954	18,309	+ 4%

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CASH FLOW FROM OPERATIONS

Cash flow from operations grew by 205% in 2003 and by 54% in Q4 compared to their respective periods in 2002. As a percentage of revenue, cash flow from operations was consistent in both years and both quarters, at 51% of revenue in 2003 compared to 46% in 2002, and 48% of revenue in Q4 of both 2003 and 2002.

Higher production volumes and higher commodity prices in 2003 are the main factors behind the increase. Pricing was not a factor in Q4 because prices actually showed a small decrease of 4% in 2003 compared to 2002.

The changes on a per unit basis showed similar results: an increase of 195% in 2003 compared to 2002 and 40% in Q4, 2003 compared to Q4, 2002.

As mentioned earlier, it is management s view that cash flow from operations is a very useful measure of performance, especially in light of Enterra s conversion to an oil and gas income trust. Cash flow from operations is the key factor in setting the monthly distribution rate. As discussed in the earnings section above, cash flow from operations is also a good benchmark when comparing results from year to year or quarter to quarter because it excludes one-time non-recurring events which may otherwise distort the financial results. Cash flow from operations is a non-GAAP measure, reconciled with GAAP net earnings in the table below:

Cash flow from operations ***(in Thousand s except for per unit/share amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Net earnings (loss)	$ (5,103)	$ 715	N/A	$ 5,004	$ 4,977	+ 1%
Add back re-organization costs	5,756	-		5,756	-	
Deduct gain on redemption of preferred shares	-	-		-	(3,111)	
Add back depletion and depreciation	6,236	3,468		23,447	9,306	
Add back (deduct) amortization of deferred financing charges	(27)	391		262	391	
Add back future income taxes	323	360		1,941	911	

Deduct amortization of deferred gain	-	(83)		(237)	(524)	
Add back non-cash expense related to value of warrants	282	-		282	-	
Cash flow from operations	$ 7,467	$ 4,851	+ 54%	$ 36,455	$ 11,950	+ 205%
Cash flow from operations as a percentage of revenue	48%	48%	0%	51%	46%	+ 11%
Cash flow from operations on a per boe basis	$ 15.59	$ 16.37	- 5%	$ 19.88	$ 14.11	+ 41%
Per unit information						
Cash flow from operations per unit/share	$ 0.37	$ 0.26	+ 40%	$ 1.92	$ 0.65	+ 195%
Average number of units/shares outstanding	20,205	18,336	+ 10%	18,954	18,309	+ 4%

CAPITAL EXPENDITURES

Capital expenditures, net of disposals, for the year ended December 31, 2003 were $33.3 million (2002 - $30.1 million) and $11.9 million for Q4 (2002 - $20.1 million). Enterra drilled 47 wells in 2003, resulting in 31 oil wells (31.0 net) and 3 gas wells (1.1 net) for an 86% success rate. Enterra drilled 62 wells (57.7 net) in 2002, resulting in 25 oil wells (23.7 net) and 37 gas wells (34.0 net). There were 15 wells drilled in Q4 of 2003 compared with 54 wells drilled in Q4 of 2002, which is why the capital expenditures in Q4, 2002 are twice as high as Q4, 2003. Proceeds on disposal of oil and gas properties were $18.3 million in 2003 (2002 - $5.8 million). These proceeds used to reduce debt and replenish working capital relate almost exclusively to the sale of the Grand Forks properties, which occurred in the second quarter of 2002 and which accounted for $5.3 million of the total proceeds.

Capital expenditures ***(in Thousand s except for percentages and per boe amounts)***

	Q4 2003	Q4 2002	*Change*	Year 2003	Year 2002	*Change*
Property acquisitions	$ 73	$ 89		$ 8,539	$ 4,829	
Proceeds on disposal of properties	(2,228)	(410)		(18,263)	(5,810)	
Drilling (exploration and development)	10,048	14,386		28,390	21,519	
Facilities and equipment	4,008	6,027		14,368	9,347	

Other	92	8		286	235	
	$ 11,993	$ 20,100	- 40%	$ 33,320	$ 30,120	+ 11%

CASH DISTRIBUTIONS

Enterra paid distributions of US$0.10 per unit for the month of December 2003 and for the first two months of 2004. The distribution for the month of March 2004 was raised to US$0.11 per unit. Cash distributions are paid on the 15th of the following month (e.g. the March distribution would be paid on April 15).

Enterra's distributions are highly dependent on commodity prices, primarily the price of crude oil. Enterra mitigates this risk by hedging some of its oil production. A detailed schedule of Enterra s hedging history and current position is included in the next section dealing with liquidity and capital resources.

For Canadian tax purposes 72.37% of the December distribution is taxable income to unitholders for the 2003 tax year. The remaining 27.63% is a tax deferred return of capital which will reduce the unitholder's cost base of the unit for purposes of calculating a capital gain or loss upon ultimate disposition of the trust units.

For U.S. tax purposes, the December distribution is a 2004 taxable event. Enterra s distributions are typically dividend income for U.S. unitholders, without any portion deemed a return of capital.

OUTLOOK 2004

Enterra s focus in 2004 continues to be on enhancing value for its unitholders by delivering a stable and growing monthly distribution, combined with a potential for a price appreciation of its trust units in the market place.

Our objectives for 2004 include:

- accretive reserve replacement through property acquisitions with development upside.
- a growing distribution from quarter to quarter.
- controlling and reducing operating costs.
- maintaining an effective development program through farm-out and joint venture arrangements.
- keeping our investors up-to-date with our plans through timely communications. a focus on per unit growth.

LIQUIDITY AND CAPITAL RESOURCES

Enterra s bank debt at December 31, 2003 was $34 million (2002 - $24.4 million). In both periods the funds were used to acquire capital assets and support ongoing operations. At December 31, 2003 Enterra s bank facility consisted of a line of credit of $39.6 million (2002 - $26.7 million). Interest on amounts drawn is based on the bank s prime rate plus 0.25%. Enterra was in full compliance with all of its bank covenants at December 31, 2003

In both 2003 and 2002 Enterra financed its ongoing operations in part by selling properties. Proceeds from such sales were $18.3 million in 2003 and $5.8 million in 2002. As a trust, Enterra is less likely to dispose of properties unless the funds from such sales can be re-invested in acquiring new properties with development upside potential as part of Enterra s reserve replacement strategy.

Enterra s preferred shares were redeemed in 2002 for $2.3 million, paid for with cash of $1.75 million and a note of $550,000. The note was subsequently settled for $325,000, resulting in a gain of $206,181 net of related legal costs.

In 2002 Enterra closed a sale-leaseback arrangement on some of its production and processing equipment for $5 million. The funds were used for the Company s 2002 drilling program. The lease agreement calls for 60 monthly payments of $88,802, with an option to purchase of $1 million on the last day of the 60th month. This arrangement is accounted for as a capital lease. At December 31, 2003 the balance outstanding on all capital leases was $4,168,548 (2002 - $4,921,598).

On January 16, 2004 Enterra entered into a financing agreement whereby Enterra will issue 1,650,000 Trust Units at a price of US$10.00 per unit for gross proceeds of US$ 16,500,000. Payment will be received pending registration of the units.

These funds will be applied towards the East Central Alberta property acquisition described below.

On January 30, 2004 the Trust closed an acquisition of properties in East Central Alberta for $19,847,000.

On February 20, 2004 the Trust completed a private placement of 1,049,400 Trust Units at a price of US$11.25 per unit for gross proceeds of US$11,805,750 (US$10,265,463 net of financing costs). These funds will be used for drilling projects which Enterra began prior to its conversion to a trust.

Capital expenditures should be approximately $5-10 million in 2004 because Enterra, as an income trust, will be distributing approximately 80% of its cash flow through its monthly distributions. Enterra s strategy for growth in 2004 will be focused on property acquisition which will be funded with a combination of additional debt and equity.

Enterra has approximately $66 million in tax pools available at December 31, 2003. (2002 - $64 million)

Enterra had several costless collars and forward contracts in place during the year in order to minimize the volatility in crude oil pricing. Below is a summary of Enterra s hedging operations in 2002 and 2003:

Hedging summary

Description	Quantity	Pricing	Gain (loss) on contract
Oil contract Oct. 1/2000 to Sept 30/2003 (sold in January 2001)	350/650 bbls of oil/day	US$24.15 to US$27.19	$1,680,000
Zero collar from November 1/2001 to April 30/2002	500 bbls of oil/day	Floor US$20 Ceiling US$24	($41,878)
Zero collar from October 1/2002 to March 31/2003	500 bbls of oil/day	Floor US$22 Ceiling US$28	($65,440)

Natural gas contract from Nov 1/2002 to March 31/2003	1,500 mcf of gas/day	C$4.60 per mcf	($486,225)
Natural gas contract from Nov 1/2002 to March 31/2003	1,500 mcf of gas/day	C$4.45 per mcf	($520,200)
Oil contracts from April 1/2003 to December 31/2003	2,000 bbls of oil/day	From US$29.50 to US$29.80	($246,937)
Contracts entered into subsequent to December 31/2003:			
Oil contracts from January 1/2003 to June 30/2004	500 bbls of oil/day	US$26.75 per barrel	
Oil contracts from January 1/2003 to June 30/2004	500 bbls of oil/day	US$26.68 per barrel	
Oil contracts from January 1/2003 to June 30/2004	1,000 bbls of oil/day	C$38.50 per barrel	
Oil contracts from July 1/2004 to December 31/2004	500 bbls of oil/day	C$40.50 per barrel	

As a trust, Enterra will distribute approximately 80% of its available cash flow to its unitholders. Future growth will be financed with a combination of additional trust units and bank debt. Enterra's level of distribution will fluctuate depending on future commodity prices and operating results. The portion of cash not distributed will be used for maintenance capital or to reduce bank debt. Management believes it has sufficient capital at year-end to meet its current requirements.

SENSITIVITIES

We are exposed to all of the normal risks inherent within the oil and gas sector, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We manage our operations in a manner intended to minimize our exposure, as described in notes 12 and 13 to the consolidated financial statements.

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. We assess the financial strength of our customers and joint venture partners through regular credit reviews in order to minimize the risk of non-payment.

Foreign Exchange Risk

We are exposed to market risk from changes in the exchange rate between U.S. and Canadian dollars. The price we receive for oil and natural gas production is based on a benchmark expressed in U.S. dollars, which is the standard for the oil and natural gas industry worldwide. Our monthly distributions are also based on a value expressed in U.S. dollars. However, we pay our operating expenses, drilling expenses and general overhead expenses in Canadian dollars. Changes to the exchange rate between U.S. and Canadian dollars can adversely affect us. When the value of the U.S. dollar increases, we receive higher revenue and when the value of the U.S. dollar declines, we receive lower revenue on the same amount of production sold at the same prices. A change of $0.01 in the U.S. to CDN dollar would impact Enterra s earnings by approximately $193,000 and its cash flow by $394,000.

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Commodity Price Risk

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If the WTI oil price were to change by US$1.00 per bbl, the impact on Enterra s earnings would be approximately $869,000 and the impact on Enterra s cash flow would be approximately $1,774,000. If natural gas prices were to change by US$0.50 per mcf, the impact on Enterra s earnings would be approximately $873,000 and the impact on Enterra s cash flow would be approximately $1,781,000.

We periodically use hedges with respect to a portion of our oil and natural gas production to mitigate our exposure to price changes. While the use of these derivative arrangements limits the downside risk of price declines, such use may also limit any benefits which may be derived from price increases.

Interest Rate Risk

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2003, we had $34 million of indebtedness bearing interest at floating rates. If interest rate were to change by one full percentage point, the net impact on Enterra s earnings would be approximately $244,000 and the net impact on Enterra s cash flow would be approximately $337,000.

Summarized below are Enterra s sensitivities to various risks, based on its 2003 operations:

Sensitivities	Estimated 2004 impact on:	
	Net Income	Cash Flow
Crude oil US$1.00/bbl change in WTI	$869,000	$1,774,000
Natural Gas US$0.50/mcf change	$873,000	$1,781,000
Foreign Exchange - $0.01 change in U.S. to CDN dollar	$193,000	$394,000
Interest rate 1% change	$244,000	$337,000

RELATED PARTY TRANSACTIONS

There were no related party transactions in 2003 or 2002

OFF BALANCE SHEET ARRANGEMENTS

There were no off balance sheet arrangements in 2003 or 2002.

COMMITMENTS

Enterra has only two ongoing commitments over the next five years, one related to the capital lease and the other related to the rental payments for our office space. The rental payments were $299,132 in 2003 (2002 - $240,255 and 2001 - $167,545). These commitments are outlined below:

	2004	2005	2006	2007	Thereafter 2008
Minimum capital lease payments	$786,889	$809,538	$877,697	$1,702,342	
Rental payments re-office space	460,447	467,717	414,770	309,990	640,920
	$1,247,336	$1,277,255	$1,292,467	$2,012,332	$640,920

Note: The above table does not include any imputed interest, as presented in note 14 of the 2003 financial statements.

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NEW ACCOUNTING PRONOUNCEMENTS

Canadian Pronouncements

In December 2001, the Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, "Hedging Relationships" (AcG-13). AcG-13 establishes certain conditions for when hedge accounting may be applied. The guideline is effective for years beginning on or after July 1, 2003. Where hedge accounting does not apply, any changes in the mark to market values of the option contracts relating to a financial period can either reduce or increase net income and net income per trust unit for that period. Enterra enters into financial instruments to manage its commodity price risk that do not qualify as hedges under the new accounting guideline. We have elected to not apply hedge accounting to any of our financial instruments. Effective January 1, 2004, we will record the fair value of financial instruments as a liability of $1.0 million on the balance sheet. Future changes in fair value of the financial instruments will be recorded as a gain or loss in oil and gas sales in the income statement.

In December 2002, the CICA approved Section 3110 Asset Retirement Obligations to harmonize Canadian GAAP with Financial Accounting Standards Board Statement No. 143. The section replaces previous guidance on future removal and site restoration costs and is effective for fiscal years beginning on or after January 1, 2004. The asset retirement obligation liability is initially measured at fair value, which is the discounted future value of the liability. The fair value is capitalized as part of the related asset and is depleted over the useful life of the asset. The liability accretes until the obligation is settled. Prior periods will be restated in accordance with the new standard. We have estimated the December 31, 2003 asset retirement obligation to be $2.2 million, based on a total future liability of $4.2 million.

The CICA issued Accounting Guideline 16, which replaces Accounting Guideline 5, Full Cost Accounting in the Oil and Gas Industry. The guideline is effective for fiscal years beginning on or after January 1, 2004 and is to be accounted for on a prospective basis. The most significant change is the modification of the ceiling test to be consistent with CICA Section 3063, Impairment of Long-lived Assets. The new guideline limits the carrying value of oil and gas properties to their fair value. There is no write down of our property, plant and equipment under either the old or the new method as of December 31, 2003.

Effective March 31, 2004, the Trust and all reporting issuers in Canada will be subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and Annual Information Form (AIF). The instrument also requires enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for the Trust to mail annual and interim financial statements and MD&A to unitholders, but rather these documents will be provided on an "as requested" basis. The Trust continues to assess the implications of this new instrument which will be implemented in 2004.

Other accounting standards issued by the CICA during the year ended December 31, 2003 are not expected to materially impact us.

U.S. Pronouncements

The following standards issued by the FASB do not impact us at this time:

(a) Interpretation No. 46, "Consolidation of Variable Interest Entities", effective for the Trust for the period ending December 31, 2004.

(b) FAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity", effective for financial statements issued after June 15, 2003.

(c) FAS No. 132 (revised 2003), "Employers   Disclosures about Pensions and Other Post Retirements Benefits - an amendment of SFAS No. 87, 88 and 106", effective for financial statements issued after December 15, 2003.

(d) FAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", effective for contracts entered into or modified after June 30, 2003.

The Trust will continue to assess the applicability of these standards in the future.

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RESULT OF OPERATIONS 2002 COMPARED TO 2001

OVERVIEW

Enterra achieved record revenue, cash flow and earnings in 2002. Enterra s growth occurred primarily in the fourth quarter of the year when revenue and cash flow doubled from the previous quarter. Enterra exited the year with a production rate of 5,335 boe/day, doubling the previous quarter exit rate of 2,456 boe/day. Enterra continued to reduce operating costs during 2002, resulting in an average cost per boe of $7.11 compared to $8.38 in 2001. Total reserves increased by 36% to 11.08 million boe with the majority of the increase coming from the Clair property. Enterra also strengthened its balance sheet by redeeming a substantial portion of its preferred shares for a gain of $3.1 million.

Summarized financial and operational data ***(in Thousand s except for volumes and per share amounts)***

	Year 2002	Year 2001	*Change*
Exit production rate (boe per day)	5,335	2,675	+ 99%
Average annual production revenue	$ 25,746	$ 20,264	+ 27%
Average annual production volumes (boe per day)	2,320	1,906	+ 22%
Cash flow from operations for the year	$ 11,950	$ 9,810	+ 22%
Cash flow per share for the year	$ 1.31	$ 1.40	- 7%
Earnings *(including $3.1 million gain on redemption of preferred shares in 2002)*	$ 4,977	$ 1,617	+ 208%
Earnings per share for the year	$ 0.54	$ 0.23	+ 134%
Average number of shares outstanding during year	9,154,491	6,992,393	+ 31%
Average price per bbl of oil during year	$ 33.86	$ 30.53	+ 11%
Average price per mcf of natural gas during year	$ 4.08	$ 3.66	+ 11%
Operating costs per boe during year	$ 7.11	$ 8.38	- 15%
General and administrative expenses per boe during year	$ 1.99	$ 0.81	+ 145%

PRODUCTION INCOME

Production income increased by 27% in 2002 from $20.3 million to $25.7 million, mainly due to the accelerated drilling program in effect during the fourth quarter of the year. Enterra drilled only eight wells in the first nine months of 2002 but drilled 54 wells in the fourth quarter alone. Commodity prices were slightly higher, on average, in 2002 than 2001 a 40% decrease.

Enterra drilled 62 wells (57.7 net) in 2002, resulting in 25 oil wells (23.7 net) and 37 gas wells (34.0 net) for a success ratio of 100%. Enterra s production in 2002 averaged 2,320 boe/day, consisting of 1,460 bbls/day of oil and 5,157 mcf/day of natural gas, for a mix of 63% oil and 37% natural gas.

Enterra exited 2002 at a rate of 5,335 boe/day, consisting of 4,205 bbls/day of oil and 6,780 mcf/day of natural gas, for a mix of 79% oil and 21% natural gas. This represents a 99% increase over the 2001 exit rate of 2,675 boe/day.

Production income ***(in Thousand s except for volumes and pricing)***

	Year 2002	Year 2001	*Change*
Crude oil and natural gas liquids	$ 18,075	$ 17,773	+ 2%
Natural gas	7,671	2,491	+ 208%
Total production income	$ 25,746	$ 20,264	+ 27%
Volumes			
Average oil production during year (in bbls/day)	1,460	1,595	- 8%
Average gas production during year (in mcf/day)	5,157	1,863	+ 177%
Average total production during year (in boe/day)	2,320	1,906	+ 22%
Exit oil production (in bbls/day)	4,205	2,065	+ 104%
Exit gas production (in mcf/day)	6,780	3,660	+ 85%
Exit total production (in boe/day)	5,335	2,675	+ 99%
Pricing			
Average price received per bbl of oil during year	$ 33.86	$ 30.53	+ 11%
Average price received per mcf of natural gas during year	$ 4.08	$ 3.66	+ 11%

PRODUCTION EXPENSES

Production expenses increased by 3% from $5.8 million in 2001 to $6 million in 2002. On a per boe basis, Enterra reduced its operating costs by 15% from $8.38 per boe in 2001 to $7.11 per boe in 2002. This trend should continue in 2003 as Enterra focuses its efforts on selected core areas.

Production expenses ***(in Thousand s except for percentages and per boe amounts)***

	Year 2002	Year 2001	*Change*
Production expenses	$ 6,018	$ 5,830	+ 3%
As a percentage of production revenue	23%	29%	- 21%
Production expenses per boe	$ 7.11	$ 8.38	- 15%

ROYALTIES

Royalties, which include Crown, freehold and overriding royalties, increased by 32% as a result of both the increased production in 2002 and the higher commodity prices in effect during the year.

Royalties ***(in Thousand s except for percentages and per boe amounts)***

	Year 2002	Year 2001	*Change*
Royalties, net of Alberta Royalty Tax Credit	$ 4,203	$ 3,182	+ 32%
As a percentage of production revenue	16%	16%	-
Royalties per boe	$ 4.96	$ 4.58	+ 8%

GENERAL AND ADMINISTRATIVE EXPENSES

General and administrative expenses increased by 198% in 2002 as a result of additional staffing requirements and higher marketing and travel costs, in addition to higher compliance costs as a result of trading on both a Canadian and U.S. exchange. Overhead recovery costs, which are a recovery of overhead costs related to capital expenditures, were also lower in 2002 as Enterra s average working interest was over 90% in 2002, compared to 53% in 2001.

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General and administrative expenses ***(in Thousand s except for percentages and per boe amounts)***

	Year 2002	Year 2001	*Change*
General and administrative expenses	$ 1,683	$ 565	+ 198%

As a percentage of production revenue	6%	3%	+ 100%
General and administrative expenses per boe	$ 1.99	$ 0.81	+ 145%

INTEREST EXPENSE

Interest expense increased in 2002 by 110% due to the higher average outstanding loan balances during the year, especially in the fourth quarter.

Interest expense ***(in Thousand s except for percentages and per boe amounts)***

	Year 2002	Year 2001	*Change*
Long-term debt, including bank debt at year-end	$ 29,358	$ 18,409	+ 59%
Interest expense	$ 1,236	$ 589	+ 110%
As a percentage of production revenue	5%	3%	+ 67%
Interest expense per boe	$ 1.46	$ 0.85	+ 72%

DEPLETION AND DEPRECIATION

Depletion and depreciation expense increased by 35% in 2002 to $9.3 million from $6.9 million in 2001. The increase is due to both a higher 2002 production rate and a higher 2002 depletable base as a result of spending in excess of $35 million in capital expenditures during the year.

Depletion and depreciation ***(in Thousand s except for percentages and per boe amounts)***

	Year 2002	Year 2001	*Change*
Depletion and depreciation expense	$ 9,306	$ 6,870	+ 35%
As a percentage of production revenue	36%	34%	+ 6%
Depletion and depreciation expense per boe	$ 10.99	$ 9.88	+ 11%

INCOME AND CAPITAL TAXES

Income taxes decreased by 60% in 2001 as a result of the reduced earnings. Current income taxes were substantially reduced as a result of the Big Horn acquisition, which provided the basis for a more effective tax structure within the

Enterra group.

Income and capital taxes ***(in Thousand s except for percentages and per boe amounts)***

	Year 2002	Year 2001	*Change*
Income tax expense	$ 1,043	$ 682	+ 53%
As a percentage of production revenue	4%	3%	+ 33%
Income tax expense per boe	$ 1.23	$ 0.98	+ 26%
Estimated tax pools			
Canadian oil and gas property expense (COGPE)	$ 20,148	$ 16,832	
Canadian exploration expense (CEE)	9,870	1,606	
Canadian development expense (CDE)	4,708	6,250	
Undepreciated capital cost (UCC)	27,109	18,464	
Other	2,331	2,152	
	$ 64,166	$ 45,304	+ 42%

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EARNINGS

Enterra s earnings for the year ended December 31, 2002 were $4.98 million (2001 - $1.62 million). This large increase was caused mainly by a $3.1 million gain on redemption of preferred shares which occurred in the first quarter of 2002. Enterra redeemed 6,123,870 of its Series 1 preferred shares with a face redemption price of $5,205,290 for $2.1 million, resulting in a gain of $3.1 million. Without this gain, earnings would have been $1.86 million, an increase of 15%. Earnings per share for the year ended December 31, 2002 were $0.54 (2001 - $0.23). The weighted average number of shares outstanding in 2002 was 9,154,491 (2001   6,992,393).

Earnings ***(in Thousand s except for number of shares and per share amounts)***

	Year 2002	Year 2001	*Change*
Earnings from operations	$ 2,909	$ 3,228	- 10%
Add gain on redemption of preferred shares	3,111	-	

Less restructuring charges	-	(929)	
Less income taxes	(1,043)	(682)	
Net earnings	$ 4,977	$ 1,617	+ 208%
Net earnings per share	$ 0.54	$ 0.23	+ 134%
Average number of shares outstanding during year	9,154,491	6,992,393	+ 31%

CASH FLOW

Cash flow from operations grew by 22% in 2002 to $11.95 million compared to $9.81 million in 2001. Cash flow per share in 2002 was $1.31 per share, a 7% decrease from 2001 when it was $1.40.

Cash flow ***(in Thousand s except for number of shares and per share amounts)***

	Year 2002	Year 2001	*Change*
Net earnings	$ 4,977	$ 1,617	+ 208%
Add back depletion and depreciation	9,306	6,870	
Add back amortization of deferred financing charges	391	-	
Add back future income taxes	911	562	
Add back deferred gain	-	1,680	
Deduct amortization of deferred gain	(524)	(919)	
Less gain on redemption of preferred shares	(3,111)	-	
Cash flow from operations	$ 11,950	$ 9,810	+ 22%
Cash flow per share	$ 1.31	$ 1.40	- 6%
Average number of shares outstanding during year	9,154,491	6,992,393	+ 31%

CAPITAL EXPENDITURES

Capital expenditures for the year ended December 31, 2002 were $35.88 million (2001 - $14.96 million). Drilling activity was minimal in the first ten months of 2002 but increased substantially in November and December. Almost $20 million was spent in the fourth quarter of 2002, representing over 50% of the entire 2002 capital expenditures. Enterra drilled 62 (57.7 net) wells in 2002, resulting in 25 (23.7 net) oil wells and 37 (34.0 net) gas wells. Only 8 wells were drilled in the first nine months of 2002. The remaining 54 wells (87% of total wells drilled in 2002) were all drilled in the fourth quarter of 2002. Proceeds on disposal of oil and gas properties were $5.8 million in 2002 (2001 - $1.7 million). These proceeds relate almost exclusively to the sale of the Grand Forks properties, which occurred in the second quarter of 2002 and which accounted for $5.3 million of the total proceeds. Finding costs, on a proved plus 1/2 probable basis, improved by 17% in 2002 to $7.72 compared to $9.30 in 2001.

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ITEM 6. Directors, Senior Management and Employees

New Enterra's officers, directors and executive officers as of December 31, 2003 were:

Name	Age	Position
Luc Chartrand	47	Chief Executive Officer, President and Director
Lynn Wiebe	46	Chief Financial Officer
Reginald J. Greenslade	40	Chairman
H.S. (Scobey) Hartley	71	Director
Norman G. Wallace	65	Director
William E. Sliney	65	Director (Mr. Sliney became a director on March 19, 2004)

Luc Chartrand.

Mr. Chartrand worked for KPMG as a Chartered Accountant from 1985 to 1988 when he became a tax manager in their Calgary office. He left shortly thereafter and worked as a consultant to several Calgary companies. He moved to Toronto in 1990 to assist in the relocation and takeover of Financial Trust by Central Capital. He remained in Toronto until 1992 when he returned to Calgary with Morgan Financial Corporation. Shortly thereafter, he joined Bonus Resource Services Corp. as its Chief Financial Officer. Mr. Chartrand joined Big Horn Resources Ltd. in the fall of 1994 and became Chief Financial Officer in 1996. He became Chief Financial Officer of Enterra in August 2001 and Chief Executive Officer, President and director of Enterra Energy Trust in November 2003.

Lynn Wiebe.

Ms Wiebe joined Enterra on October 1, 2003 as Chief Financial Officer. Ms. Wiebe is a Chartered Accountant and held various progressive positions at KPMG LLP from 1980 to 1986. From 1986 to 1995, Ms. Wiebe was employed by Gulf Canada Resources in supervisory positions in Financial Reporting, Corporate Reporting, Oil Marketing and Accounting and various other areas within the company. From 1995 to May 2001 Ms. Wiebe left the permanent workforce to pursue other interests. During the period from May 2001 to October 2002, she provided financial services to a number of organizations, including Trans Canada Pipelines and a private mortgage company, through contracting and consulting engagements. In May of 2003, Ms. Wiebe was employed by Control-F1 Corporation, an eSupport software company, as their Chief Financial Officer, until she joined Enterra in October, 2003.

Reginald (Reg) J. Greenslade

. Mr. Greenslade was President, CEO and Director of Enterra Energy Corp from the fall of 2001 until November 2003 and continues as Chairman of Enterra Energy Trust. Enterra Energy Corp. was formed by the combination of Big Horn Resources Ltd. and Westlinks Resources Ltd in the fall of 2001. He is also the Chairman, Chief Executive Officer and director of JED Oil Inc. He was a director of PASW Inc., a software development company, from February 2001 to July 2001. From 1995 until the formation of Enterra, Mr. Greenslade was the President, CEO and Director of Big Horn Resources Ltd. Prior to his position with Big Horn, Mr. Greenslade was with CS Resources Limited in the areas of exploitation engineering and project management from 1993 to 1995. Prior to 1993, Mr. Greenslade was employed by Saskatchewan Oil and Gas Corporation in the capacities of project management, production, and reservoir engineering. He has extensive experience with secondary recovery schemes and is recognized for his work in the specialized field of horizontal well technology. All the above companies were publicly traded in either the U.S., Canada, or both, during the periods indicated.

H.S. (Scobey) Hartley.

Mr. Hartley has a Bachelor of Science degree in Geology from Texas Tech University. Mr. Hartley has been a director of Enterra since May, 2000. Mr. Hartley was the President of Prism Petroleum Ltd. and a predecessor company from December, 1990 through December, 1996. Mr. Hartley has been the Chairman of Prism Petroleum Ltd. since January, 1997. Mr. Hartley has served as the President of Faster Oilfield Services since June, 1995, and was the President of Cayenne Energy Corp. from 1990 to 1996. Mr. Hartley was the President and a Director of Scaffold Connection Corporation from February, 2000 to November, 2001. Mr. Hartley has been a Director of Cathedral Energy Services Ltd. since June, 2001.

Norman G. Wallace.

Mr. Wallace has been a director of Enterra since May, 2000. Mr. Wallace resigned as a director of Enterra in August, 2001 and was reappointed in June, 2002. He has been the owner of Wallace Construction Specialties Ltd. since 1972. Mr. Wallace received a Bachelor of Commerce degree from the University of Saskatchewan in 1968.

William E. Sliney.

Mr. Sliney became a director on March 19, 2004. He has been the president of PASW, Inc. since August 2001 and was chairman from October 2000 to August 2001. Previously Mr. Sliney was the chief financial officer for Legacy Software Inc. from 1995 to 1998. From 1993 to 1994, Mr. Sliney was chief executive officer for Gumps. Mr. Sliney received his masters in business administration from the University of California at Los Angeles.

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Board of Directors

New Enterra is authorized to have a board of at least three directors and no more than ten. New Enterra currently has five directors. Directors are elected for a term of about one year, from annual meeting to annual meeting, or until an earlier resignation, death or removal. Each officer serves at the discretion of the board or until an earlier resignation or death. There are no family relationships among any of New Enterra's directors or officers. Alberta securities laws requires that New Enterra have at least two independent outside directors who are not officers or employees of Enterra.

Currently directors of New Enterra receive an annual retainer of $ 10,000. Directors are also entitled to be compensated for their out-of-pocket costs, including travel and accommodation, relating to their attendance at any directors' meeting. Finally, the directors of New Enterra are entitled to participate in our trust unit option plan. During the year ended December 31, 2003, there were no options granted to the current directors (not including options granted to a director who is also a named executive officer). Except as described herein, no compensation by way of annual retainer or meeting fees was paid to directors for acting in such capacity in the year ended December 31, 2003.

Committees of the Board of Directors

New Enterra's Board of Directors currently has an audit committee, a compensation committee, a corporate governance committee and a reserves committee.

Audit Committee.

New Enterra's audit committee consists of Mr. Sliney (Chairman), Mr. Hartley and Mr. Wallace, all three being independent directors. The audit committee reviews in detail and recommends approval of the full board of our annual and quarterly financial statements; recommends approval of the remuneration of our auditors to the full board; reviews the scope of the audit procedures and the final audit report with the auditors, and reviews our overall accounting practices and procedures and internal controls with the auditors.

Compensation Committee.

New Enterra's compensation committee consists of Mr. Hartley (Chairman), Mr. Wallace and Mr. Greenslade. The compensation committee recommends approval to the full board of the compensation of the Chief Executive Officer, the annual compensation budget for all other employees, bonuses, grants of stock options and any changes to our benefit plans.

Corporate Governance Committee.

New Enterra's corporate governance committee consists of Mr. Wallace (Chairman), Mr. Greenslade and Mr. Hartley. The corporate governance committee determines the scope and frequency of periodic reports to the board concerning issues relating to overall financial reporting, disclosure and other communications with all stakeholders.

Reserves Committee

. New Enterra's reserves committee consists of Mr. Wallace (Chairman) and Mr. Hartley. The reserves committee reviews and recommends approval to the full board of Enterra s annual reserve report as prepared by independent reservoir engineers.

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Executive Compensation

The following table provides a summary of compensation earned during the last fiscal year ended December 31, 2003 by our executive officers during 2003.

All monetary amounts are in Canadian dollars.

Annual Compensation	Long-Term Compensation

Name and Principal Position	Year	Salary ($)	Bonus ($)	Other Annual Compensation ($)	Awards: Securities Under Options/ SARs Granted (#)	Awards: Restricted Shares or Restricted Share Units ($)	Payouts: LTIP Payouts ($)	All Other Compensation ($)
Luc Chartrand [1]	2003	182,495	298,180					
President and Chief	2002	158,355						
Executive Officer	2001	133,365						
Lynn Wiebe	2003	28,200	6,000		5,000			
Chief Financial	2002							
Officer	2001							

(1) Mr. Chartrand was Chief Financial Officer in 2001, 2002 and for most of 2003. He became Chief Executive Officer of New Enterra on November26, 2003

(2)

Ms. Wiebe became Chief Financial Officer of NewEnterra on October 1, 2003

Management Contracts

We have no employment contracts with any employees.

Trust Units Options

We grant trust unit options from time to time to directors, officers, key employees, and consultants. The terms and conditions of the options, in accordance with resolutions of our board of directors and the policies of the Toronto Stock Exchange, will not exceed a term of five years. The option price may be at a discount to market price, which discount will not, in any event, exceed that permitted by any stock exchange on which our shares are listed for trading.

Ten percent of our of issued and outstanding trust units from time to time are reserved for issuance pursuant to trust unit options. The aggregate number of trust units reserved for issuance under option grants, together with any other employee trust unit option plans, options for services and employee trust unit purchase plans, will not exceed ten percent of our issued and outstanding trust units. In addition, the aggregate number of trust units so reserved for issuance to any one person shall not exceed five percent of the issued and outstanding trust units.

If an optionee ceases to be eligible due to the loss of corporate office or employment for any reason other than death, the option terminates not later than 30 days after the loss of such corporate office; provided that in the event of termination of employment for cause, the board of directors may resolve that the option shall terminate on the date of such termination. Option agreements also provide that estates of deceased participants can exercise their options for a period not exceeding one year following death.

Trust Unit

Options Granted During the Most Recently Completed Financial Year

There were no trust unit options granted during the fiscal year ended December 31, 2003.

Option Grants During Fiscal Year Ended December 31, 2003

	Individual Grants				Potential Realizable Value at Assumed Annual Rate of Stock Price Appreciation for Option Term (1)	
	Number of Shares of Common Stock	**Percentage of Total OptionsGranted to Employees inYear Ending Dec. 31, 2003**	**Exercise Price Per Share**	**Expiration Date**	- 5%	- 10%
Lynn Wiebe	5,000	15.87 %	$18.58	Sep 30/08	$25,667	$56,716

(1) Assumed annual appreciation rates are established by regulations and are not a forecast of future appreciation. The amounts shown are pre-tax and assume the options will be held throughout the entire five-year term. If trust units do not increase in value after the grant date of the options, the options are valueless.

Aggregated Option Exercises During the Most Recently Completed Financial Year and Financial Year End Option Values

The following table sets forth the aggregate of options exercised by our executive officers during the year ended December 31, 2003 and the December 31, 2003 year-end values for options granted to the executive officers. All monetary amounts are in Canadian dollars. These options relate to Old Enterra shares, prior to the trust conversion.

Name	**Securities Exercised (#)**	**Aggregate Value Realized ($)**	**Unexercised Options at FY-End Exercisable/ Unexercisable (#)**	**Value of Unexercised in-the-Money Options at FY-End Exercisable/ Unexercisable ($)(1)**
Luc Chartrand	72,500	$1,153,230	Nil	Nil/Nil

Lynn Wiebe	5,000	$ 20,100	Nil	Nil/Nil

(1) The closing price of our trust units on the Toronto Stock Exchange on the last trading day in December, 2003 was $ 14.51.

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ITEM 7. Major Shareholders and Related Party Transactions

A. Major Shareholders

PRINCIPAL STOCKHOLDERS

The following table sets forth information regarding beneficial ownership of our trust units as of December 31, 2003, by:

- each person who is known by us to beneficially own more than 5% of our outstanding trust units;
- each of our executive officers and directors; and
- all executive officers and directors as a group.

Trust units not outstanding but deemed beneficially owned because an individual has the right to acquire the trust units within 60 days are treated as outstanding when determining the amount and percentage of trust units owned by that individual and by all directors and executive officers as a group.

	Number of trust units Beneficially Owned	Percentage of shares outstanding
Luc Chartrand [1]	45,450	0.24%
Lynn Wiebe [1]	5,000	0.02%
Reginald J. Greenslade [1]	195,147	1.03%
H.S. (Scobey) Hartley [1]	84,400	0.45%
Norman G. Wallace [1]	70,000	0.37%
William E. Sliney [1][2]	-	

All directors and executive officers as a group (five persons)	399,997	2.11%

Notes:

(1) The address of each officer and director is Suite 2600, 500 - 4th Avenue S.W., Calgary, Alberta, Canada T2P 2V6.

(2) Mr. Sliney did not become a director or Enterra until March 19, 2004.

B. Related Party Transactions

There were no related party transactions in 2003 or 2002

C. Interests of Experts and Counsel

Not Applicable

ITEM 8. Financial Information

A. Consolidated Financial Statements and Other Financial Information

Pages F-1 to F-14.

B. Significant Changes

None.

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ITEM 9. The Offer and Listing

A. Offer and Listing details

Not Applicable, except for Item 9A (4).

Price Range of Common Stock and Trading Markets

On November 28, 2003 the buisness of Old Enterra was reorganized as an income trust. In conjunction with this reorganization holders of Enterra Energy Corp. common stock received two trust units for each share of common stock held or non-registered exchangeable shares convertible into an equal number of trust units. All historical information before November 28, 2003 in the following tables has been restated to reflect this exchange.

Old Enterra's shares commenced trading on the TSX Venture Exchange ("TSXV") under the symbol "WLX" during the quarter ended September 30, 1998. Our shares traded on the National Quotation Bureau's pink sheets ("Pink Sheets") under the symbol "WLKSF" from April 26, 2000 to January 10, 2001 when the shares commenced trading on the Nasdaq SmallCap Market under the symbol "EENC" and under the symbol "ENT" on the TSX Venture Exchange ("TSX"). On May 21, 2003 the shares commenced trading on the Nasdaq National Market under the symbol "EENC." On June 20, 2003 the shares commenced trading on the Toronto Stock Exchange under the symbol "ENT". Following our reorganization as an income trust in November 2003 our trust units commenced trading on the Nasdaq National Market and Toronto Stock Exchange under the same symbols as the common stock which was retired as a result of the reorganization.

The following table sets forth the bid prices, in Canadian or U.S. dollars, as reported by the TSXV, TSX and NASDAQ National and SmallCap Markets/pink sheets, for the periods shown, as restated for periods prior to November 28, 2003 to reflect the 2:1 conversion from common shares to trust units.

	Toronto Stock Exchange/TSX Venture Exchange (Cdn. $ s)		Nasdaq SmallCap Market/Pink Sheets (U.S. $ s)		Nasdaq National Market (U.S. $ s)	
Five most recent full fiscal years:	High	Low	High	Low	High	Low
Year ended December 31, 2003	14.10	4.995	7.75	3.245	10.91	4.625
Year ended December 31, 2002	5.75	1.30	3.75	0.735	n/a	n/a
Year ended December 31, 2001	3.75	1.15	2.405	0.825	n/a	n/a
Year ended December 31, 2000	3.90	2.225	2.305	1.705	n/a	n/a
Year ended December 31, 1999	0.525	0.205	n/a	n/a	n/a	n/a
Year ended December 31, 2003:						
Quarter ended December 31, 2003	14.10	5.775	n/a	n/a	10.91	4.625
Quarter ended September 30, 2003	12.935	8.54	n/a	n/a	9.625	6.00
Quarter ended June 30, 2003	10.25	8.925	7.75	4.045	n/a	n/a
Quarter ended March 31, 2003	7.00	4.995	4.75	3.245	n/a	n/a
Year ended December 31, 2002:						
Quarter ended December 31, 2002	5.75	3.00	3.75	1.90	n/a	n/a
Quarter ended September 30, 2002	3.225	2.30	2.095	1.475	n/a	n/a
Quarter ended June 30, 2002	2.745	2.135	1.74	1.125	n/a	n/a

Quarter ended March 31, 2002	2.48	1.30	1.165	0.735	n/a	n/a
Year ended December 31, 2001:						
Quarter ended December 31, 2001	1.875	1.15	1.195	0.825	n/a	n/a
Quarter ended September 30, 2001	2.50	1.375	1.70	0.875	n/a	n/a
Quarter ended June 30, 2001	3.225	2.35	2.125	1.39	n/a	n/a
Quarter ended March 31, 2001	3.75	2.5	2.405	1.61	n/a	n/a
Six most recent months ended:						
October 2003	13.01	9.25	n/a	n/a	9.95	6.755
November 2003	14.10	6.25	n/a	n/a	10.91	4.75
December 2003	7.54	5.775	n/a	n/a	5.815	4.625
January 2004	8.625	6.505	n/a	n/a	6.295	5.05
February 2004	8.90	7.87	n/a	n/a	6.70	5.825
March 2004	9.40	8.955	n/a	n/a	7.195	6.70

B. Plan of Distribution

Not Applicable

C. Markets

See Item 9.A

D. Selling Shareholders

Not Applicable

E. Dilution

Not Applicable

ITEM 10. ADDITIONAL INFORMATION

A. Share Capital

DESCRIPTION OF SECURITIES

Trust Units

An unlimited number of trust units may be created and issued pursuant to our trust indenture. Each trust unit entitles the holder thereof to one vote at any meeting of the unitholders and represents an equal fractional undivided beneficial interest in any distribution from us, including net income, net realized capital gains or other amounts, and in our net assets in the event of termination or winding up of our business. All trust units rank among themselves equally and ratably without discrimination, preference or priority. Each trust unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require us to redeem any or all of the trust units held by such holder.

Exchangeable Shares

In conjunction with our reorganization we issued exchangeable shares that are intended to be the economic equivalent of trust units. We issued a total of 2,000,000 exchangeable shares.

The exchangeable shares are convertible at any time into trust units at the option of the holder based on an exchange ratio. The exchange ratio is increased monthly based on the cash distribution paid on the trust units divided by the ten day weighted average unit price preceding the distribution payment date. From November 25 to December 31, 2003, a total of 4,404 exchangeable shares were converted into 4,404 trust units at the exchange ratio 1:1 prevailing at the time. Cash distributions are not paid on the exchangeable shares. On the third anniversary of the issuance of the exchangeable shares, subject to our extension , or at our option when the aggregate number of issued and outstanding exchangeable shares is less than 1,000,000, the exchangeable shares will be redeemed for trust units based upon the value of that number of trust units equal to the exchange ratio on the redemption date. The exchangeable shares are not listed for trading on an exchange.

Holders of exchangeable shares can require us to redeem their shares at any time and carry special voting rights. The special voting rights equal the number of trust units into which the exchangeable shares are then exchangeable multiplied by the number of votes to which the holder of one trust unit is then entitled.

Ownership Restrictions

There is no law or government decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to non-resident holders of trust units, other than withholding tax requirements.

There is no limitation imposed by Canadian law or by our charter or other charter documents on the right of a non-resident to hold or vote our trust units, other than as provided by the Investment Canada Act, the North American Free Trade Agreement Implementation Act (Canada) and the World Trade Organization Agreement Implementation Act. The Investment Canada Act requires notification and, in certain cases, advance review and approval by the Government of Canada of the acquisition by a "non-Canadian" of "control" of a "Canadian business," each as defined in the Investment Canada Act. In general, the threshold for review will be higher in monetary terms for a member of the World Trade Organization or North American Free Trade Agreement.

Transfer Agent and Registrar

The transfer agent and registrar for our trust units is Olympia Trust Company at its principal offices in Calgary and Toronto, Canada.

TRUST UNITS ELIGIBLE FOR FUTURE SALE

Future sales of substantial amounts of our trust units in the public market, in either Canada or the United States, or even the perception that such sales could occur, could adversely affect the market price for our trust units and could impair our future ability to raise capital through an offering of our equity securities.

We have outstanding 18,951,556 trust units, assuming no exercise of outstanding warrants and options. All these units are freely tradable, without restrictions imposed by applicable securities laws.

We intend to register the trust units issuable pursuant to our trust unit option plan. At December 31, 2003 there were no options outstanding to purchase trust units, all of which would be eligible for immediate resale in Canada, and in the United States by persons who are not affiliates of Enterra.

Our affiliates may reoffer and resell trust units in Canada, in accordance with the foregoing, provided that such trust units are offered and sold by them pursuant to Rule 903 of Regulation S under the Securities Act and that at the time the Toronto Stock Exchange continues to be the principal market for our trust units.

B. Trust Indenture / Memorandum and Articles of Association

The Trust

Enterra Energy Trust is an open ended unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to the Trust Indenture.

The principal undertaking of the Trust is to issue trust units and to acquire and hold debt instruments, royalties and other interests. The direct and indirect wholly owned subsidiaries of the Trust carry on the business of acquiring and holding interests in petroleum and natural gas properties and assets related thereto.

The Trustee is prohibited from acquiring any investment which (a) would result in the cost amount to the Trust of all "foreign property" (as defined in the *Income Tax Act* (Canada)) which is held by the Trust to exceed the amount prescribed by section 5000 of the regulations to the *Income Tax Act* (Canada) or (b) would result in the Trust not being considered either a "unit trust" or a "mutual fund trust" for purposes of the *Income Tax Act* (Canada).

Enterra is authorized to issue an unlimited number of trust units. See "Item 10 A Share Capital." The trust unitholders have no rights to share in Enterra s profits, are subject to no redemption or sinking fund provisions, have no liability for further capital calls and are not subject to any discrimination due to number of trust units owned.

By not more than 50 days or less than seven days in advance of a distribution, the board may establish a record date for the determination of the persons entitled to such dividend. Any distribution unclaimed after a period of six years from the record date shall be forfeited and revert to Enterra.

The rights of trust unitholders can be changed at any time in a unitholders meeting where the modifications are approved by 66 2/3% of the unitholders represented by proxy or in person at the meeting.

All unitholders are entitled to vote at annual or special meetings of unitholders, provided that they were unitholders as of the record date. The record date for unitholders meetings may precede the meeting date by no more than 50 days and not less than 21 days, providing that notice by way of advertisement is given to unitholders at least seven days before such record date. Notice of the time and place of meetings of unitholders may not be less than 21 or greater than 50 days prior to the date of the meeting.

New Enterra

New Enterra is amalgamated under the laws of the Province of Alberta, Canada (corporation number 207913385). The Articles of Amalgamation and by-laws provide no restrictions as to the nature of the business operations of New Enterra.

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The governing legislation requires a director to inform New Enterra, at a meeting of the Board of Directors, of any interest in a material contract or proposed material contract with New Enterra. No director may vote in respect of any such contract made by them with New Enterra or in any such contract in which they are interested, and such director shall not be counted for purposes of determining a quorum. However, these provisions do not apply to (i) an arrangement by way of security for money lent to or obligations undertaken by them: (ii) a contract relating primarily to their remuneration as a director, officer, employee or agent of New Enterra or an affiliate: (iii) a contract for indemnity or insurance of the director as allowed under the governing legislation: or (iv) a contract with an affiliate.

The Board of Directors may exercise all powers of New Enterra to borrow or raise money, and to give guarantees, and to mortgage or charge its properties and assets, and to issue debentures, debenture stock and other securities, outright or as security for any debt, liability or obligation of New Enterra or any third party.

There are no age limit requirements regarding retirement of directors and there is no minimum share ownership required for a director s election to the board.

All directors of New Enterra are elected at each annual meeting of unitholders of the Trust and cumulative voting is not permitted.

C. Material Contracts

None

D. Exchange Controls

There is no law or government decree or regulation in Canada that restricts the export or import of capital, or affects the remittance of dividends, interest or other payments to non-resident holders of trust units, other than withholding tax requirements.

There is no limitation imposed by Canadian law or by our acharter or our charter documents on the right of a non-resident to hold or vote sour trust units, other than as provided by the "Investment Canada Act", the "North American Free Trade Agreement Implementation Act (Canada)" and the "World Trade Organization Agreement Implementation Act."

The Investment Canada Act requires notification and, in certain cases, advance review and approval by the Government of Canada of the acquisition by a "non-Canadian" of "control" of a "Canadian business", each as defined in the Investment Canada Act. In general, the threshold for review will be higher in monetary terms for a member of the World Trade Organization or North American Free Trade Agreement.

E. Taxation

Canadian Federal Income Tax Considerations

T

he following is a summary of the material Canadian federal income tax considerations under the *Income Tax Act* (Canada) (the "Tax Act") in respect of the acquisition of trust units pursuant this offering generally applicable to purchasers who (i) hold trust units as capital property for purposes of the Tax Act, and (ii) at all material times deal at arm's length, and are not affiliated, with Enterra and New Enterra for purposes of the Tax Act. Generally, trust units will be considered to be capital property to a holder who does not hold such securities in the course of carrying on a business and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain Canadian resident unitholders who might not otherwise be considered to hold their trust units as capital property may, in certain circumstances, be entitled to make an irrevocable election in accordance with subsection 39(4) of the Tax Act to have such trust units treated as capital property.

This summary is not applicable to either a unitholder that is a "financial institution" or a "specified financial institution", as defined for purposes of the Tax Act, or a unitholder, an interest in which would be a "tax shelter investment" under the Tax Act.

This summary is based upon the provisions of the Tax Act and the regulations thereunder ("Tax Regulations") in force as of the date hereof, all specific proposals to amend the Tax Act and the Tax Regulations that have been publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "Proposed Amendments") and Canadian counsel's understanding of the current published administrative and assessing policies of the Canada Customs and Revenue Agency (the "CCRA").

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This summary is not exhaustive of all possible Canadian federal income tax considerations applicable to the acquisition of trust units and, except for the Proposed Amendments, does not take into account or anticipate any changes in the law, whether by legislative, governmental or judicial action or changes in the administrative and assessing practices of the CCRA. This summary does not take into account any provincial, territorial or foreign tax considerations, which may differ significantly from those discussed herein.

This summary is of a general nature only and is not intended to be relied on as legal or tax advice or representations to any particular investor. Consequently, potential investors are urged to seek independent tax advice in respect of the consequences to them of the acquisition of trust units having regard to their particular circumstances.

Residents of Canada

This portion of the summary is applicable to a unitholder who, for the purposes of the Tax Act and at all relevant times, is resident, or deemed to be resident, in Canada.

Status of the Trust

Based upon a certificate from New Enterra, the Trust qualifies as a mutual fund trust under the provisions of the Tax Act and the balance of the summary assumes that the Trust will continue to so qualify. [Enterra has also advised Canadian counsel that it intends to apply to the CCRA for the Trust to be registered as a "registered investment" under the Tax Act from inception, and this summary further assumes that the Trust will be so registered.]

The requirements to qualify as a mutual fund trust for purposes of the Tax Act include:

1. the sole undertaking of the Trust must be the investing of its funds in property (other than real property or interests in real property), the acquiring, holding, maintaining, improving, leasing or managing of any real property (or an interest in real property) that is capital property of the Trust, or any combination of these activities;

2. the Trust must comply on a continuous basis with certain requirements relating to the qualification of the trust units for distribution to the public, the number of unitholders and the dispersal of ownership of trust units. In this regard, there must be at least 150 unitholders, each of whom owns not less than one "block" of trust units having a fair market value of not less than $500. A "block" of trust units means 100 trust units if the fair market value of one trust unit is less than $25; and

3. continuously from the time of its creation, all or substantially all of the Trust's property must consist of property other than property that would be "taxable Canadian property" for purposes of the Tax Act.

The Trust has certain restrictions on its activities and its powers and certain restrictions on the holding of taxable Canadian property, such that it is reasonable to expect that the requirements will be satisfied. However, Canadian counsel can provide no assurances that the requirements will continue to be met.

If the Trust were not to so qualify as a mutual fund trust or were not to be registered as a registered investment from inception, the income tax considerations would in some respects be materially different from those described below.

Taxation of the Trust

The Trust is subject to tax in each taxation year on its income or loss for the year, computed as though it were a separate individual resident in Canada. The taxation year of the Trust will end on December 31 of each year.

The Trust will be required to include in its income for each taxation year (i) all interest on the Series A Notes that accrues to, becomes receivable or is received by it before the end of the year, except to the extent that such interest was included in computing its income for a preceding year (ii) all interest on the CT Note that accrues to, becomes receivable or is received by it before the end of the year, except to the extent that such interest was included in computing its income for a preceding year (iii) the net income of Commercial Trust paid or payable to the Trust in the year and (iv) all amounts in respect of any oil and gas royalties, if any, held by the Trust including any amounts required to be reimbursed to the grantor of the royalty in respect of Crown charges.

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In computing its income, the Trust will generally be entitled to deduct reasonable administrative expenses incurred to earn income. The Trust will be entitled to deduct the costs incurred by it in connection with the issuance of trust units on a five-year, straight-line basis (subject to pro-ration for short taxation years). The Trust may also deduct amounts which become payable by it to unitholders in the year, to the extent that the Trust has net income for the year after the inclusions and deductions outlined above and to the extent permitted under the Tax Act. An amount will be considered to have become payable to a unitholder in a taxation year only if it is paid in that year by the Trust or the unitholder is entitled in that year to enforce payment of the amount. Under the Trust Indenture, net income of the Trust for each year will be paid or made payable by way of cash distributions to the unitholders. The Trust Indenture also contemplates other situations in which the Trust may not have sufficient cash to distribute all of its net income by way of such cash distributions. In such circumstances, such net income will be payable to unitholders in the form of the issuance by the Trust of additional trust units ("Reinvested trust units"). Accordingly, it is anticipated that the Trust will generally not have any taxable income for the purposes of the Tax Act.

Under the Trust Indenture, income received by the Trust may be used to finance cash redemptions of trust units. A redemption of trust units that is effected by a distribution by the Trust to a unitholder of Series A Notes will be treated as a disposition by the Trust of such Series A Notes for proceeds of disposition equal to the fair market value thereof and may give rise to a taxable capital gain to the Trust.

The Trust will be entitled for each taxation year to reduce (or receive a refund in respect of) its liability, if any, for tax on its net taxable capital gains by an amount determined under the Tax Act based on the redemption or retraction of trust units during the year (the "Capital Gains Refund"). In certain circumstances, the Capital Gains Refund for a particular taxation year may not completely offset the Trust's tax liability on net realized capital gains for such taxation year.

For purposes of the Tax Act, the Trust generally intends to deduct, in computing its income and taxable income, the full amount available for deduction in each year. As a result of such deductions and the Trust's entitlement to a Capital Gains Refund, it is expected that the Trust will not be liable for any material amount of tax under the Tax Act. However, no assurance can be given in this regard.

[The Trust will apply to be a "registered investment" under the Tax Act from the Trust's inception. It may be eligible to be registered if it is a mutual fund trust, and it may have its registration revoked by the CCRA if it ceases to be a mutual fund trust and did not otherwise qualify for registered investment status. Assuming that the Trust becomes a registered investment, the Trust may be subject to a special tax under Part XI of the Tax Act if it acquires or holds foreign property in excess of the limits provided in the Tax Act or enters into certain agreements to acquire shares of a corporation at a price that may differ from the fair market value of the shares at the time of acquisition. Based on Enterra's certificate as to certain factual matters and the terms of the Trust Indenture, which restrict its investments in foreign property, the Trust will not become liable for such tax.]

If the Trust ceases to qualify as a mutual fund trust, the Trust may be required to pay tax under Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Trust may have material adverse tax consequences for certain unitholders.

Taxation of unitholders

<u>Income from trust units</u>

The income of a unitholder from the trust units will be considered to be income from property for the purposes of the Tax Act. Any deduction or loss of the Trust for the purposes of the Tax Act cannot be allocated to and treated as a deduction or loss of a unitholder.

A unitholder will generally be required to include in computing income for a particular taxation year of the unitholder the portion of the net income of the Trust for a taxation year, including taxable dividends and net taxable capital gains, that is paid or becomes payable to the unitholder in that particular taxation year, whether such amount is payable in cash or in Reinvested trust units. Provided that appropriate designations are made by Commercial Trust and the Trust, such portion of the Trust's net taxable capital gains and taxable dividends, if any, as are paid or payable to a unitholder will effectively retain their character as taxable capital gains and taxable dividends, respectively, and will be treated as such in the hands of the unitholder for purposes of the Tax Act.

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The amount of any net taxable capital gains designated by the Trust to a unitholder will be included in the unitholder's income under the Tax Act for the year of disposition as a taxable capital gain. See "*Taxation of Capital Gains and Capital Losses*" above. The non-taxable portion of net realized capital gains of the Trust that is paid or becomes payable to a unitholder in a year will not be included in computing the unitholder's income for the year. Any other amount in excess of the net income of the Trust that is paid or becomes payable by the Trust to a unitholder in a year will generally not be included in the unitholder's income for the year. However, a unitholder is required to reduce the adjusted cost base of the trust units held by such unitholder by each amount payable to the unitholder otherwise than as proceeds of disposition of trust units (except to the extent that the amount either was included in the income of the unitholder or was the unitholder's share of the non-taxable portion of the net capital gains of the Trust, the taxable portion of which was designated by the Trust in respect of the unitholder). To the extent that the adjusted cost base of a trust unit is less than zero, the negative amount will be deemed to be a capital gain of a unitholder from the disposition of the trust unit in the year in which the negative amount arises. See "*Taxation of Capital Gains and Capital Losses*" below.

The amount of dividends designated by the Trust to a unitholder will be subject to, among other things, the gross-up and dividend tax credit provisions for unitholders who are individuals, the refundable tax under Part IV of the Tax Act applicable to "private corporations" and "subject corporations" (as defined under the Tax Act), and the deduction in computing taxable income in respect of dividends received by taxable Canadian corporations. In general, net income of the Trust that is designated as taxable dividends from taxable Canadian corporations or as net taxable capital gains may increase an individual unitholder's liability for alternative minimum tax.

Cost of trust units

The cost to a unitholder of a trust unit will generally include all amounts paid by the unitholderfor the trust unit. Reinvested trust units issued to a unitholder as a non-cash distribution of income will have a cost equal to the amount of income distributed by the issuance of such Reinvested trust units. This cost will be averaged with the adjusted cost base of all other trust units held by the unitholder as capital property in order to determine the respective adjusted cost base of each trust unit.

Disposition of trust units

Upon the disposition or deemed disposition by a unitholder of a trust unit, whether on a redemption or otherwise, the unitholder will generally realize a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition exceed (or are less than) the aggregate of (i) such unitholder's adjusted cost base of the trust units disposed of, determined immediately before the disposition and (ii) any reasonable costs of disposition. A redemption of trust units in consideration for cash distributed to the unitholder in satisfaction of the Market Redemption Price, or the issuance of a Redemption Note by the Trust in satisfaction of the Market Redemption Price, will be a disposition of such trust units for proceeds of disposition equal to the cash or the principal amount of the Redemption Note, as the case may be. Where trust units are redeemed by the distribution of Series A Notes to the unitholder, the proceeds of disposition to the unitholder of such trust units will generally be equal to the fair market value of the Series A Notes so distributed less any capital gain or income realized by the Trust in connection with such redemption which has been designated by the Trust to the redeeming unitholder.

Where a unitholder that is a corporation or a trust (other than a mutual fund trust) disposes of a trust unit, the unitholder's capital loss from the disposition will generally be reduced by the amount of dividends from taxable Canadian corporations previously designated by the Trust to the unitholder, except to the extent that a loss on a previous disposition of a trust unit has been reduced by such dividends. Similar rules apply where a corporation or trust (other than a mutual fund trust) is a member of a partnership that disposes of trust units. See "*Taxation of Capital Gains and Capital Losses*" below.

The cost to a unitholder of any Series A Notes distributed to the unitholder by the Trust on a redemption of trust units will be equal to the fair market value of such Series A Notes at the time of distribution, excluding any accrued interest thereon. Such a unitholder will be required to include in income interest on such Series A Notes (including interest that had accrued to the date of distribution of the Series A Notes to the unitholder) in accordance with the provisions of the Tax Act. To the extent that the unitholder is required to include in income any interest that had accrued to the date of distribution of the Series A Notes, an offsetting deduction will be available in computing the unitholder's income from the Trust.

A unitholder will be required to include in income interest on the Redemption Notes in accordance with the provisions of the Tax Act.

A unitholder that is corporation that is throughout a relevant taxation year a "Canadian-controlled private corporation", as defined in the Tax Act, may be liable to pay an additional refundable tax of 6 2/3% on certain investment income, including taxable capital gains and interest.

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Tax-Exempt Unitholders

Provided that the Trust qualifies as a "mutual fund trust" or is a "registered investment" for purposes of the Tax Act at a particular time, the trust units will be qualified investments for Exempt Plans. If the Trust ceases to qualify as a mutual fund trust and the Trust's registration as a registered investment under the Tax Act is revoked, the trust units will cease to be qualified investments under the Tax Act for Exempt Plans. Where, at the end of a month, an Exempt Plan holds trust units or other properties that are not qualified investments, the Exempt Plan may, in respect of that month, be required to pay a tax under Part XI.1 of the Tax Act.

Exempt Plans will generally not be liable for tax in respect of any distributions received from the Trust or any capital gain arising on the disposition of trust units. However, where an Exempt Plan receives trust property as a result of a redemption of trust units, some or all of such property may not be qualified investments under the Tax Act for the Exempt Plans and could, as discussed above, give rise to adverse consequences to the Exempt Plans (and, in the case of registered retirement savings plans or registered retirement income funds, to the annuitants thereunder). Accordingly, Exempt Plans that own trust units should consult their own tax advisors before deciding to exercise their redemption rights thereunder.

Based on Enterra's certificate as to certain factual matters, provided that the Trust is a "mutual fund trust" and restricts its holdings of foreign property within the limits provided under the Tax Act (30% based on cost in 2003), or the Trust is a "registered investment" within the meaning of the Tax Act (see "Taxation of the Trust" above), the trust units will not constitute foreign property for Exempt Plans, registered pension funds or plans or other persons subject to tax under Part XI of the Tax Act. Registered education savings plans are not subject to tax under Part XI of the Tax Act.

Taxation of Capital Gains and Capital Losses

Generally, one half of any capital gain (a "taxable capital gain") realized by a unitholder or a unitholder on the disposition of capital property in a taxation year must be included in the income of the holder for the year, and one half of any capital loss (an "allowable capital loss") realized in a taxation year may be deducted from taxable capital gains realized by the holder in that year. Allowable capital losses for a taxation year in excess of taxable capital gains for that year generally may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net capital gains realized in such years, to the extent and under the circumstances described in the Tax Act.

A corporation that is throughout a relevant taxation year a "Canadian-controlled private corporation", as defined in the Tax Act, may be liable to pay an additional refundable tax of 6 2/3% on certain investment income, including taxable capital gains realized in the particular taxation year.

Capital gains realized by an individual may give rise to a liability for alternative minimum tax.

Non-Residents of Canada

This portion of the summary is applicable to a unitholder who, for the purposes of the Tax Act, and at all relevant times is not resident in Canada and is not deemed to be resident in Canada, does not use or hold, and is not deemed to use or hold, trust units in, or in the course of, carrying on business in Canada, and is not an insurer who carries on an insurance business in Canada and elsewhere (a "Non-Resident Holder").

Taxation of the Trust

The tax treatment of the Trust under the Tax Act is as generally described above under "Residents of Canada Taxation of the Trust". If the Trust ceases to qualify as a mutual fund trust for purposes of the Tax Act, the Trust may be required to pay tax under Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Trust may have adverse tax consequences to certain unitholders.

Taxation of Income from Trust Units

All income of the Trust determined in accordance with the Tax Act (except taxable capital gains) paid or credited by the Trust in a taxation year to a Non-Resident Holder will generally be subject to Canadian withholding tax at a rate of 25%, subject to a reduction of such rate under an applicable income tax treaty or convention, whether such income is paid or credited in cash or in Reinvested trust units. See "*Residents of Canada Taxation of the Trust*" above. Provided that certain conditions are satisfied, the rate of Canadian withholding tax may be reduced to nil in respect of amounts that are paid or credited by the Trust to a Non-Resident Holder as income of or from the Trust where the amount that can reasonably be regarded as being derived from interest that would not have been subject to Canadian withholding tax under the Tax Act had the interest been paid directly to the Non-Resident Holder instead of to the Trust.

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Taxable capital gains realized by the Trust and paid or payable by the Trust in a taxation year to a Non-Resident Holder will generally be deemed to be taxable capital gains of the Non-Resident Holder from the disposition of capital property and may be subject to tax under the Tax Act. See "*Taxation of Capital Gains and Capital Losses on Dispositions of Taxable Canadian Property*" above.

The cost to a Non-Resident Holder of a trust unit will generally include all amounts paid by the Non-Resident Holder for the trust unit. Reinvested trust units issued to a Non-Resident Holder as a non-cash distribution of income will have a cost equal to the amount of income distributed by the issuance of such Reinvested trust units for purposes of the Tax Act. This cost will be averaged with the adjusted cost base of all other trust units held by the Non-Resident Holder as capital property in order to determine the respective adjusted cost base of each trust unit.

Disposition of trust units

Upon a redemption of trust units, a Non-Resident Holder will be subject to Canadian withholding tax at a rate of 25%, subject to reduction under any applicable tax treaty or convention, of the amount that is the Non-Resident Holder's share of taxable capital gains realized by the Trust as a result of the redemption (other than taxable capital gains that are paid or payable to the Non-Resident Holder by the Trust under the Tax Act) and of any accrued interest on the Series A Notes that is transferred to the Non-Resident Holder on the redemption.

Taxable capital gains realized by the Trust on a disposition of Series A Notes to a Non-Resident Holder on a redemption of trust units, which are paid or payable by the Trust in a taxation year to a Non-Resident Holder will generally be deemed to be taxable capital gains of the Non-Resident Holder from the disposition of capital property and may be subject to tax under the Tax Act. See "*Taxation of Capital Gains and Capital Losses on Dispositions of Taxable Canadian Property*" below.

A Non-Resident Holder will be subject to taxation in Canada in respect of a capital gain or capital loss realized on the disposition of trust units only to the extent such units constitute "taxable Canadian property", as defined in the Tax Act, and the Non-Resident Holder is not afforded relief under an applicable income tax treaty or convention.

trust units will normally not be taxable Canadian property at a particular time provided that (i) the Non-Resident Holder, persons with whom the Non-Resident Holder does not deal at arm's length (within the meaning of the Tax Act), or the Non-Resident Holder together with such persons, did not own or have an interest in or option in respect of 25% or more of the issued trust units at any time during the 60-month period preceding the particular time (ii) the Trust is a mutual fund trust at the time of the disposition, and (iii) the trust units are not otherwise deemed to be taxable Canadian property.

A Non-Resident Holder of trust units that are not taxable Canadian property will not be subject to tax under the Tax Act on the redemption or disposition of such units.

A Non-Resident Holder whose trust units constitute taxable Canadian property generally will realize a capital gain (or capital loss) on the redemption or disposition of such units equal to the amount by which the proceeds of disposition exceeds (or is less than) the aggregate of (i) such unitholder's adjusted cost base of its trust units so redeemed or disposed, determined immediately before the redemption or disposition and (ii) any reasonable costs of disposition. A redemption of trust units in consideration for cash distributed to the Non-Resident Holder in satisfaction of the Market Redemption Price, or the issuance of a Redemption Note by the Trust in satisfaction of the Market Redemption Price, will be a disposition of such trust units for proceeds of disposition equal to the cash or the principal amount of the Redemption Note, as the case may be. Where trust units are redeemed by the distribution of Series A Notes to the Non-Resident Holder, the proceeds of disposition to the Non-Resident Holder of such trust units will generally be equal to the fair market value of the Series A Notes so distributed less any capital gain or income realized by the Trust in connection with such redemption which has been designated by the Trust to the redeeming unitholder.

Where a Non-Resident Holder that is a corporation or a trust (other than a mutual fund trust) disposes of a trust unit, the Non-Resident Holder's capital loss from the disposition will generally be reduced by the amount of dividends from taxable Canadian corporations previously designated by the Trust to the unitholder, except to the extent that a loss on a previous disposition of a trust unit has been reduced by such dividends. Similar rules apply where a corporation or trust (other than a mutual fund trust) is a member of a partnership that disposes of trust units. See "*Taxation of Capital Gains and Capital Losses on Dispositions of Taxable Canadian Property"* below.

The cost to a Non-Resident Holder of any Series A Notes distributed to the Non-Resident Holder by the Trust on a redemption of trust units will be equal to the fair market value of such Series A Notes at the time of distribution, excluding any accrued interest thereon.

Taxation of Capital Gains and Capital Losses on Dispositions of Taxable Canadian Property

Generally, one half of any capital gain (a "taxable capital gain") realized by a Non-Resident Holder on a disposition of taxable Canadian property in a taxation year must be included in the income of the Non-Resident Holder for the year, and one half of any capital loss (an "allowable capital loss") realized by a Non-Resident Holder on a disposition of taxable Canadian property in a taxation year may be deducted from taxable capital gains realized by the Non-Resident

Holder in that year. Allowable capital losses for a taxation year in excess of taxable capital gains for that year generally may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net capital gains realized in such years, to the extent and under the circumstances described in the Tax Act.

In certain cases where a Non-Resident Holder realizes a capital gain from a disposition of property that constitute taxable Canadian property to such Non-Resident Holder, it is possible that any such capital gain may be exempt from tax for the purposes of the Tax Act by virtue of the provisions of an income tax treaty or convention between Canada and the country of residence of the Non-Resident Holder. Conversely, the amount of any capital loss resulting from the disposition of such property may not be deductible against capital gains of the Non-Resident Holder for the purposes of the Tax Act by virtue of the provisions of such income tax treaty or convention. unitholders who are Non-Resident Holders are advised to consult with their tax advisors regarding the application of any applicable income tax treaty or convention.

If a Non-Resident Holder disposes of taxable Canadian property, the Non-Resident Holder is required to file a Canadian income tax return for the taxation year in which such disposition occurs.

United States Federal Income Tax Considerations

The following summary discusses the material United States federal income tax considerations that are generally applicable to a holder of Enterra common shares and trust units who is a citizen or resident of the United States, who is a corporation, partnership or other entity that is created or organized in or under the laws of the United States, who is subject to United States federal income tax on a net income basis with respect to Enterra common shares or who will be subject to United States federal income tax on a net income basis with respect to trust units that are acquired (a "U.S. Holder").

This summary does not purport to be a complete description of all of the United States federal income tax considerations that may be relevant to a U.S. Holder. In particular, this summary deals only with U.S. Holders who hold Enterra common shares as a capital asset. This summary does not address the tax treatment of U.S. Holders who are subject to special tax rules. Nor does this summary discuss the United States federal income tax considerations for a partner in a partnership which holds Enterra common shares or trust units.

Flow-through of Items of Income, Gain, Loss, Deduction and Credit

A U.S. holder will include in each of its taxable years its share of our items of income, gain, loss, deduction and credit and certain deductions in respect of depletion for each of our taxable years that ends within or with such U.S. holder's taxable year on its own United States federal income tax return in order to determine its liability for United States federal income tax whether or not we make any distribution to it. Such items of income, gain, loss, deduction and credit will be determined on United States federal income tax principles and will as a general matter retain their character and source as they flow through us to the holders of trust units. The use by a holder of trust units of certain of our items of deduction, loss and credit will be limited as is discussed below.

As a result, a U.S. holder whose taxable year is not the same as our taxable year and who disposes of all of its trust units

after the close of its taxable year but before the end of our taxable year will be required to include in income for its then taxable year its share of more than one year of our items of income, gain, loss, deduction and credit. A U.S. Holder's share of our items of income, gain, loss, deduction and credit will, as a general matter, be its percentage interest in us of such items..

Tax Rates and Creditability of Certain Canadian Income Taxes.

As general matter, the character and source of a U.S. holder's share of the items of the income, gain, loss, deduction and credit is determined at our level and flows through us to each such U.S. holder in determining its liability for United States federal income tax including any effect of the alternative minimum tax. Each U.S. holder should consult with its tax advisors as to the impact of holding trust units on its liability for the United States federal income tax and the alternative minimum tax. The rules as to the use of foreign income taxes as credits are complex, the following discussion is only a summary of a portion thereof, and a U.S. holder should discuss these matters with its own tax advisors.

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United States Federal Income Tax Rates

A U.S. holder's share of our oil and gas production is treated as ordinary income subject to cost depletion. Such ordinary income is generally subject to the income tax at a maximum rate of 35 percent. Dividends that are received from a foreign corporation are currently subject to the United States federal income tax at a maximum rate of 15 percent under certain conditions. If a U.S. holder who is an individual, then any dividends received would be subject to the United States federal income tax at a maximum rate of 15 percent so long as (i) the shares in respect of which the dividends are paid have been held (subject to certain tolling rules) for more than 60 days during the 120 day period which begins 60 days before the those shares go ex-dividend, (ii) such U.S. holder is not under an obligation to make certain related payments with respect to substantially similar or related property, (iii) we are not either a foreign personal holding company, a foreign investment company or a passive foreign investment company, and (iv) we are eligible for the benefits of the income tax treaty between Canada and the United States. It is likely that the Internal Revenue Service will take the position that such holding period requirement is applied when an individual holds shares indirectly through us to the individual's holding period in trust units.

For a U.S. holder who is an individual, any long-term capital gain that is realized on the sale or other disposition of trust units (including any part of a distribution that is treated as gain on such shares that is a long-term capital gain) would be subject to tax at a maximum rate of 15 percent until the end of 2008 under current law. Each U.S. holder should discuss with its own advisor whether a person whose holding period in us is less than one year can claim such 15 percent tax rate.

Credits for Canadian Income Taxes

As a general matter, any Canadian income taxes that are withheld from distributions are foreign income taxes that, subject to generally applicable limitations under United States law, may be used by a U.S. holder as a credit against its United States federal income tax liability or as a deduction (but only for a taxable year for which such U.S. holder elects to do so with respect to all foreign income taxes). So long as we are a partnership for United States federal income tax purposes, the provisions of Section 901(k) of the Internal Revenue Code should not apply. If we were a corporation for such purposes, then a U.S. Holder would not be able to claim the foreign tax credit with respect to any such Canadian tax that is withheld on a distribution that we made unless such U.S. holder had held the trust units for a minimum period (subject to certain tolling rules) of at least 16 days during the 30 day period beginning on the date which is 15 days before the date on which the trust units went ex-dividend with respect to such dividend or to the extent such U.S. holder is under an obligation to make related payments with respect to substantially similar or related property. It is likely that the Internal Revenue Service will take the position that the holding period requirement that is summarized in the preceding sentence is measured as to an individual partner of us in respect of any Canadian taxes paid by us in respect of dividends that we receive by the holding period in the trust units.

The limitation under United States law on foreign taxes that may be used as credits is calculated separately with respect to specific classes of income or "baskets." That is, the use of foreign taxes that are paid with respect to income in any such basket as a credit is limited to a percentage of the foreign source income in that basket. For such purposes, a U.S. holder's share of our income, gain, loss and deductions is generally in the passive basket if it holds less than 10 percent of the trust units. Its share of the dividends and the income will be from foreign sources, but the amount of foreign source income of an individual is only a fraction of the dividend income that is subject to the 15 percent maximum rate. Under rules of general application, a portion of a U.S. holder's interest expense and other expenses can be allocated to, and thereby reduce, the foreign source income in any basket.

Any gain that is recognized by a U.S. Holder on the sale of a trust unit that is recognized because a distribution thereon is in excess of basis in that security will generally constitute income from sources within the United States for U.S. foreign tax credit purposes and will therefore not increase the ability to use foreign taxes as credits.

Tax Consequences if We are Determined to be a Passive Foreign Investment Company

Although we do not expect to be a passive foreign investment company, or PFIC, it will be a PFIC if either (a) 75 percent or more of its gross income in a taxable year, including the pro rata share of the gross income of any company, U.S. or foreign, in which it is considered to own 25 percent or more of the shares by value, is passive income (as defined in the pertinent provisions of the Internal Revenue Code or (b) 50 percent or more of its assets (including the pro rata share of the assets of any company in which it is considered to own 25 percent or more of the shares by value), are held for the production of, or produce, passive income. Although we believe that we are not currently a PFIC and do not expect that we will become a PFIC, there is no assurance in that regard.

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If we were a PFIC, and a U.S. holder did not make an election to treat it as a qualified electing fund (there is no assurance that it will be able to make such an election) or elect to make a mark-to-market election (again, there is no assurance that it will be able to make such an election) then distributions on our stock that exceed 125 percent of the average distributions received by the U.S. holder in the shorter of the three previous taxable years or the U.S. holder's holding period for the trust units before the taxable year of distribution and the entire amount of gain that is realized by a U.S. holder upon the sale of the trust units would be subject to an additional United States income tax that approximates (and in some cases exceeds) the value of presumed benefit of a deferral of United States income taxation that was available because we are a foreign corporation.

Tax-Exempt Organizations and Other Investors

Ownership of trust units by employee benefit plans, other tax-exempt organizations, non-resident aliens, foreign corporations, other foreign persons and regulated investment companies or mutual funds raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them.

Employee benefit plans and most other organizations exempt from federal income tax, including individual retirement accounts and other retirement plans, are subject to federal income tax on unrelated business taxable income. We are unable to provide any assurance that the income that we recognize in respect of the royalty or in respect of any of our other assets will not be unrelated business taxable income.

A regulated investment company or "mutual fund" (as such terms are used in the Internal Revenue Code) is required in order to maintain its special status under the Internal Revenue Code to derive 90 percent or more of its gross income from interest, dividends and gains from the sale of stocks or securities or foreign currency or specified related sources. A significant amount of our gross income may not be any such type of income.

Administrative Matters

Information Returns and Audit Procedures

We expect to furnish to each unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes the unitholder s share of our income, gain, loss, deduction and credits for the preceding taxable year. In preparing this information, which will not be reviewed by tax counsel, we will take various accounting and reporting positions, some of which have been mentioned earlier, to determine the share of income, gain, loss and deduction. We cannot assure you that those positions will yield a result that conforms to the requirements of the Internal Revenue Code Treasury regulations or administrative interpretations of the Internal Revenue Service. Any challenge by the Internal Revenue Service could negatively affect the value of the trust units.

The Internal Revenue Service may audit our federal income tax information returns. Adjustments resulting from an Internal Revenue Service audit may require each unitholder to adjust a prior year's tax liability, and possibly may result in an audit of its return. Any audit of a unitholder's return could result in adjustments not related to our returns. Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the Internal Revenue Service and tax settlement proceedings.

The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. The Tax Matters Partner will make some elections on our behalf and on behalf of unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against unitholders for items in our returns. The Tax Matters Partner may bind a unitholder with less than a one percent profits interest in us to a settlement with the Internal Revenue Service unless that unitholder elects, by filing a statement with the Internal Revenue Service, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any unitholder having at least one percent interest in profits or by any group of unitholders having in the aggregate at least a five percent interest in profits. However, only one action for judicial review will go forward, and each unitholder with an interest in the outcome may participate.

A unitholder must file a statement with the Internal Revenue Service identifying the treatment of any item on its federal income tax return that is not consistent with the treatment of the item on our return. Intentional or negligent disregard of this consistency requirement may subject a unitholder to substantial penalties.

Nominee Reporting

Persons who hold an interest trust units as a nominee for another person are required to furnish to us:

the name, address and taxpayer identification number of the beneficial owner and the nominee;

whether the beneficial owner is:

(i) a person that is not a United States person;

(ii) a foreign government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

(iii) a tax-exempt entity;

the amount and description of trust units held, acquired or transferred for the beneficial owner; and

specific information including the dates of acquisitions and transfers means of acquisitions and transfers, and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on the trust units they acquire, hold or transfer for their own account. A penalty of $50 per failure, up to a maximum of $100,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to us. The nominee is required to supply the beneficial owner of the trust units with the information furnished to us.

Registration as a Tax Shelter

The Internal Revenue Code requires that "tax shelters" be registered with the Secretary of the Treasury. Although we may not be a "tax shelter" for such purposes, we have applied to register as a "tax shelter" with the Secretary of the Treasury in light of the substantial penalties that might be imposed if registration is required and not undertaken.

Issuance of a tax shelter registration number does not indicate that investment in us or the claimed tax benefits have been reviewed, examined or approved by the Internal Revenue Service.

We will supply our tax shelter registration number to you when one has been assigned to us. A unitholder who sells or otherwise transfers a trust unit in a later transaction must furnish the registration number to the transferee. The penalty for failure of the transferor of a unit to furnish the registration number to the transferee is $100 for each failure. A unitholder must disclose our tax shelter registration number on its tax return on which any deduction, loss or other benefit we generates is claimed or on which any of our income is included. A unitholder who fails to disclose the tax shelter registration number on its return, without reasonable cause for that failure, will be subject to a $250 penalty for each failure. Any penalties discussed are not deductible for federal income tax purposes.

Reportable Transactions

Certain Treasury regulations require taxpayers to report specific information on Internal Revenue Service Form 8886 if they participate in a "reportable transaction." A transaction may be a reportable transaction based upon any of several factors, including the existence of book-tax differences common to financial transactions, one or more of which may be present with respect to your investment in the trust units. Investors should consult their own tax advisor concerning the application of any of these factors to an investment in the trust units. Congress is considering legislative proposals that, if enacted, would impose significant penalties for failure to comply with these disclosure requirements.

Other Tax Considerations

Each U.S. holder is urged to investigate the legal and tax consequences, under the laws of pertinent jurisdictions, of acquiring and holding the trust units. Accordingly, each prospective unitholder is urged to consult its tax counsel or other advisor with regard to those matters. Further, it is the responsibility of each unitholder to file all state, local and foreign, as well as United States federal tax returns that may be required.

F. Dividends and Paying Agents

Not Applicable

G. Statement by Experts

Not Applicable

H. Documents on Display

Any statement in this annual report about any of our contracts or other documents is not necessarily complete. If the contract or document is filed as an exhibit, the contract or document is deemed to modify the description contained in this registration statement. You must review the exhibits themselves for a complete description of the contract or document.

We intend to provide our unitholders with annual reports containing consolidated financial statements audited by an independent chartered accounting firm and will make available to unitholders quarterly reports containing unaudited consolidated financial data for the first three quarters of each year. We are subject to the information and reporting requirements of the Securities and Exchange Act of 1934 and file periodic reports, proxy statements and other information with the SEC. However, we are exempt from the rules under the Exchange Act prescribing the furnishing and content of proxy statements, and our officers, directors and principal stockholders are exempt from the reporting and short-swing profit recovery provisions contained in Section 16 of the Exchange Act. Under the Exchange Act, we are not required to publish financial statements as frequently or as promptly as U.S. companies. Such reports, proxy statements and other information filed with the SEC may be inspected at the public reference facilities maintained by the Commission at Judiciary Plaza, 450 5th Street N.W., Washington, D.C. 20549. Copies of these materials may be obtained at prescribed rates from the Commission at that address. The reports, proxy statements and other information can also be inspected on the Commission s Web site at

www.sec.gov.

If you are a unitholder, you may request a copy of these filings at no cost by contacting us at:

Enterra Energy Trust

Suite 2600, 500 4th Avenue S.W.

Calgary, Alberta, Canada

T2P 2V6

(403) 213-2502

I. Subsidiary Information

Not Applicable

Item 11. Qualitative and Quantitative Disclosures about Market Risk

We are exposed to al of the normal risks inherent within the oil and gas sector, including commodity price risk, foreign-currency rate risk, interest rate risk and credit risk. We manage our operations in a manner intended to minimize our exposure, as described in notes 12 and 13 to the consolidated financial statements.

Credit Risk

Credit risk is the risk of loss resulting from non-performance of contractual obligations by a customer or joint venture partner. A substantial portion of our accounts receivable are with customers in the energy industry and are subject to normal industry credit risk. We assess the financial strength of our customers and joint venture partners through regular credit reviews in order to minimize the risk of non-payment.

Foreign Exchange Risk

We are exposed to market risk from changes in the exchange rate between U.S. and Canadian dollars. The price we receive for oil and natural gas production is based on a benchmark expressed in U.S. dollars, which is the standard for the oil and natural gas industry worldwide. Our monthly distributions are also based on a value expressed in U.S. dollars. However, we pay our operating expenses, drilling expenses and general overhead expenses in Canadian dollars. Changes to the exchange rate between U.S. and Canadian dollars can adversely affect us. When the value of the U.S. dollar increases, we receive higher revenue and when the value of the U.S. dollar declines, we receive lower revenue on the same amount of production sold at the same prices. A change of $0.01 in the U.S. to CDN dollar would impact Enterra s earnings by approximately $193,000 and its cash flow by $394,000.

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Commodity Price Risk

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for crude oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If the WTI oil price were to change by US$1.00 per bbl, the impact on Enterra s earnings would be approximately $869,000 and the impact on Enterra s cash flow would be approximately $1,774,000. If natural gas prices were to change by US$0.50 per mcf, the impact on Enterra s earnings would be approximately $873,000 and the impact on Enterra s cash flow would be approximately $1,781,000.

We periodically use hedges with respect to a portion of our oil and natural gas production to mitigate our exposure to price changes. While the use of these derivative arrangements limits the downside risk of price declines, such use may also limit any benefits which may be derived from price increases.

Interest Rate Risk

Interest rate risk exists principally with respect to our indebtedness that bears interest at floating rates. At December 31, 2003, we had $34 million of indebtedness bearing interest at floating rates. If interest rate were to change by on full percentage point, the net impact on Enterra s earnings would be approximately $244,000 and the net impact on Enterra s cash flow would be approximately $337,000.

Summarized below are Enterra s sensitivities to various risks, based on its 2003 operations:

Sensitivities	Estimated 2004 impact on:	
	Net Income	Cash Flow
Crude oil US$1.00/bbl change in WTI	$869,000	$1,774,000
Natural Gas US$0.50/mcf change	$873,000	$1,781,000
Foreign Exchange - $0.01 change in U.S. to CDN dollar	$193,000	$394,000
Interest rate 1% change	$244,000	$337,000

Item 12. Description of Securities Other Than Equity Securities.

Not Applicable

-

Part II

Item 13. Defaults, Dividends Arrearages and Delinquencies

None

Item 14. Material Modifications to the Rights of Security Holders and Use of Proceeds

Not Applicable

Item 15. Controls and Procedures

(a)

Evaluation of disclosure controls and procedures. Our Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of Enterra s disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) as of the end of the period covered by this report (the "Evaluation Date"), have concluded that, as of the Evaluation Date, our disclosure controls and procedures were adequate and effective to ensure that material information relating us and our consolidated subsidiaries would be made known to them by others within those entities.

(b) Changes in internal controls.

There were no significant changes in our internal controls or in other factors that could significantly affect our disclosure controls and procedures subsequent to the Evaluation Date, nor were there any significant deficiencies or material weaknesses in such disclosure controls and procedures requiring corrective actions. As a result, no corrective actions were taken.

Item 16. [Reserved]

Item 16A. Audit Committee Financial Expert

The chairman of our audit committee, William E. Sliney, possesses the attributes required of an audit committee financial expert.

Item 16B. Code of Ethics

We have not yet adopted a Code of Ethics. We plan to formalize and adopt a Code of Ethics that applies to all executive officers during the year ending December 31, 2004.

Item 16C. Principal Accountant Fees and Services

Deloitte & Touche LLP have audited our annual financial statements since our 2002 fiscal year. In addition, Deloitte & Touche LLP reviews our interim financial statements commencing with the nine months ended September 30, 2002. Deloitte & Touche LLP acted as our independent auditor for the fiscal years ended December 31, 2003 and 2002.

The audit fees billed to us by Deloitte & Touche LLP for services performed in 2003 and 2002 were $170,900 and $52,500 respectively.

Audit Fees

Audit fees are fees billed for the audit of our annual consolidated financial statements and for the reviews of our quarterly financial statements submitted on Form 6-K. Additionally, audit fees include consents, reviews related to the Information Circular and Proxy Statement and other services related to Canadian and SEC matters.

Pre-Approval Policies and Procedures

The audit committee approves all audit, audit-related services, tax services and other services provided by Deloitte & Touche LLP. Any services provided by Deloitte & Touche LLP that are not specifically included within the scope of the audit must be pre-approved by the audit committee in advance of any engagement. Under the Sarbanes-Oxley Act of 2002, audit committees are permitted to approve certain fees for audit-related services, tax services and other services pursuant to a de minimus exception prior to the completion of an audit engagement. In 2003, none of the fees paid to Deloitte & Touche LLP were approved pursuant to the de minimus exception.

Item 16D. Exemptions from the Listing Standards for Audit Committees.

Not Applicable.

Item 16E. Purchases of Equity Securities by the Issuer and Affiliated Purchasers.

Not Applicable.

PART III

Item 17. Financial Statements

We have responded to Item 18 in lieu of responding to this item.

Item 18. Financial Statements

The Consolidated Financial Statements of Enterra Energy Trust are attached as follows:

Item 19. Exhibits

Number

Exhibit

2.1	Amalgamation Agreement dated May 27, 1998 between Temba Resources Ltd. and PTR Resources Ltd. pursuant to which the Registrant was amalgamated under the Business Corporations Act (Alberta) on June 30, 1998.
2.2	Letter Agreement dated August 12, 1999 pursuant to which the Registrant acquired all of the issued and outstanding shares of 759795 Alberta Ltd.
2.3	Notice of Intention to File a Normal Course Issuer Bid.
3.1	Certificate of Amalgamation and attached Articles of Amalgamation of the Registrant dated and filed June 30, 1998.
3.2	By-laws of the Registrant.
3.3	Enterra Energy Trust Amended And Restated Trust Indenture (1)

4.1	Form of Warrant Trust Indenture between the Registrant and Montreal Trust Company of Canada providing for the issuance of the Warrants.
4.2	Form of Warrant Agreement between the Registrant and the Representatives providing for the issuance of the Underwriters' Warrants.
10.1	Credit Facility Letter Agreement between the Alberta Treasury Branches and the Registrant as Borrower dated April 19, 2000.
10.2	Promissory Notes dated June 5, 2000 granted by Westlinks to each of Glenn Russell, Patrick Williams Advisors, William J. Gordica, F. Jack Wright, Lawrence W. Underwood and Sapphire Capital Inc.
10.3	Purchase and Sale Agreement dated April 6, 2000 between Sabre Exploration Ltd. and the Registrant.
10.4	Purchase and Sale Agreement dated October 1, 2000 between the Registrant and Compton Petroleum Corporation.
10.5	Consulting Agreement dated October 13, 2000 between Westlinks Resources Ltd. and Wells Gray Resort & Resources Ltd.
10.6	Arrangement Agreement among Westlinks Resources Ltd. and 3779041Canada Ltd. and Big Horn Resources Ltd.
10.7	Information Circular and Proxy Statement for the Plan of Arrangement between Big Horn Resources Ltd. and Westlinks Resources Ltd.
12.1	Certifications of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act
12.2	Certifications of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act
13.1	Certifications of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act
13.2	Certifications of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act
(1)	the description of our trust units contained in our amendment to our registration statement on Form 8-A12G/A dated November 28, 2003

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Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

Enterra Energy Trust

By: Enterra Energy Corp.

Administrator of the Trust

By: /s/ Luc Chartrand

Name: Luc Chartrand

Title: Chief Executive Officer

April 26, 2004

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Auditors Report

To the Unitholders of Enterra Energy Trust:

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

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

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

The consolidated financial statements for the year ended December 31, 2001 were audited by other auditors who expressed an opinion without reservation on those consolidated financial statements in their report dated March 6, 2002.

(signed) Deloitte & Touche LLP

Chartered Accountants

Calgary, Canada

March 5, 2004

Comments by Auditor on Canada-United States of America Reporting Difference

In the United States of America, reporting standards for auditors also require the addition of an explanatory paragraph (following the opinion paragraph) outlining changes in accounting principles that have been implemented in the financial statements. As discussed in Note 2f to the financial statements, the Trust changed its method of accounting for stock-based compensation to conform to the new Canadian Institute of Chartered Accountants Handbook recommendations Section 3870. Our report to the Unitholders, dated March 5, 2004, is expressed in accordance with Canadian reporting standards which do not require a reference to such changes in accounting principles in the auditors report when the change is properly accounted for and adequately disclosed in the financial statements.

(signed) Deloitte & Touche LLP

Chartered Accountants

Calgary, Canada March 5, 2004

Auditors Report

We have audited the consolidated statements of earnings and retained earnings and cash flows of Enterra Energy Corp for the year ended December 31, 2001. These financial statements are the responsibility of the company s management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the Company s operations and cash flows for the year ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.

Canadian generally accepted accounting principles vary in certain significant respects from accounting principles generally accepted in the United States. Application of accounting principles generally accepted in the United States would have affected the results of operations for the year ended December 31, 2001to the extent summarized in note 17 to the consolidated financial statements.

(signed) KPMG LLP

Chartered Accountants

Calgary, Canada

March 6, 2002

Enterra Energy Trust

Consolidated Balance Sheets

As at December 31

(Expressed in Canadian dollars)

	2003	2002
Assets		
Current assets		
Cash	**$65,643**	$108,017
Accounts receivable	**8,742,690**	7,314,050
Deposit on land purchase (note 16)	**2,015,000**	-
Prepaid expenses and deposits	**461,727**	656,685
	11,285,060	8,078,752
Property and equipment (note 4)	**104,821,285**	94,354,313
Deferred financing charges	**123,208**	284,040
	$116,229,553	$102,717,105
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities (note 5)	**$12,208,390**	$20,661,005
Distributions payable to unitholders	**2,451,402**	-
Income taxes payable	**120,000**	155,424
Bank indebtedness (note 6)	**33,959,733**	24,436,640
Current portion of long-term debt (note 7)	**782,930**	808,917
	49,522,455	46,061,986
Provision for future abandonment and site restoration costs	**1,529,244**	934,857
Future income tax liability (note 8)	**14,011,400**	12,070,101
Long-term debt (note 7)	**3,385,618**	4,112,681
Deferred gain (note 13)	**-**	237,463

Series 1 preferred shares (note 11)	**-**	636,690
	68,448,717	64,053,778
Unitholders Equity		
Unitholders capital (note 9)	**32,838,163**	29,665,075
Exchangeable shares (note 9)	**3,457,050**	-
Contributed surplus (note 9)	**-**	65,029
Accumulated earnings	**13,937,025**	8,933,223
Accumulated distributions	**(2,451,402)**	-
	47,780,836	38,663,327
Hedging contracts (note 13)		
Commitments and guarantees (notes 14 and 15)		
Subsequent events (note 16)		
	$116,229,553	$102,717,105

Approved on behalf of the Board:

Reg Greenslade Director

Bill Sliney Director

See accompanying notes to consolidated financial statements

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Enterra Energy Trust

Consolidated Statements of Earnings and Accumulated Earnings

Years Ended December 31

(Expressed in Canadian dollars)

	2003	2002	2001
Revenue			
Oil and gas	**$72,096,975**	$25,745,676	$20,264,396
Expenses			

Royalties	**17,656,055**	4,202,880	3,182,340
Production	**12,762,376**	6,017,921	5,829,613
General and administrative	**3,385,072**	1,682,773	565,270
Interest	**1,748,932**	1,235,872	589,169
Amortization of deferred financing charges	**262,135**	390,800	-
Depletion, depreciation and future site restoration	**23,447,300**	9,306,500	6,869,912
	59,261,870	22,836,746	17,036,304
Earnings before the following	**12,835,105**	2,908,930	3,228,092
Restructuring charges (note 1)	**(5,756,075)**	-	(929,037)
Gain on redemption of preferred shares (note 11)	**-**	3,111,471	-
Earnings before income taxes	**7,079,030**	6,020,401	2,299,055
Income taxes (note 8)			
Current	**133,929**	132,000	120,000
Future	**1,941,299**	911,000	562,000
	2,075,228	1,043,000	682,000
Net earnings	**5,003,802**	4,977,401	1,617,055
Accumulated earnings, beginning of year	**8,933,223**	3,955,822	2,338,767
Accumulated earnings, end of year	**$13,937,025**	$8,933,223	$3,955,822
Earnings per unit/share (note 10)			
Basic	**$0.26**	$0.27	$0.12
Diluted	**$0.26**	$0.26	$0.12

See accompanying notes to consolidated financial statements

Enterra Energy Trust

Consolidated Statements of Cash Flows

Years Ended December 31

(Expressed in Canadian dollars)

	2003	2002	2001
Cash provided by (used in):			
Operations			
Net earnings	**$5,003,802**	$4,977,401	$1,617,055
Add non-cash items:			
Depletion, depreciation and future site restoration	**23,447,300**	9,306,500	6,869,912
Future income taxes	**1,941,299**	911,000	562,000
Deferred gain	-	-	1,680,031
Amortization of deferred gain	**(237,463)**	(523,839)	(918,729)
Amortization of deferred financing charges	**262,135**	390,800	-
Gain on redemption of preferred shares	**-**	(3,111,471)	-
Valuation of Warrants	**281,648**	-	-
	30,698,721	11,950,391	9,810,269
Net change in non-cash working capital items:			
Accounts receivable	**(1,428,640)**	(1,017,411)	(1,371,654)
Prepaid expenses and deposits	**194,959**	(73,627)	(161,941)
Accounts payable and accrued liabilities	**(8,452,616)**	11,671,616	2,205,753
Income taxes payable	**(35,424)**	(7,679)	(1,153,068)
	20,977,000	22,523,290	9,329,359
Financing			
Bank indebtedness	**9,523,093**	6,027,736	1,055,904
Long-term debt	**(753,050)**	4,704,098	-
Deferred financing charges	**(101,302)**	(549,840)	-
Redemption of preferred shares	**(636,690)**	(2,557,425)	-
Repurchase of shares	**-**	(59,971)	(753,300)
Exercise of options and warrants	**6,283,461**	96,812	5,457,625

	14,315,512	7,661,410	5,760,229
Investing			
Property and equipment additions	**(51,577,278)**	(35,881,256)	(14,958,086)
Deposit on land purchase	**(2,015,000)**	-	-
Acquisition of Big Horn Resources Ltd. (note 3)	**-**	-	(2,190,048)
Proceeds on disposal of property and equipment	**18,262,806**	5,809,940	1,700,500
Investments	**-**	-	422,000
Future abandonment and site restoration costs	**(5,414)**	(48,731)	(22,033)
	(35,334,886)	(30,120,047)	(15,047,667)
Increase (decrease) in cash	**(42,374)**	64,653	41,921
Cash, beginning of year	**108,017**	43,364	1,443
Cash, end of year	**$65,643**	$108,017	$43,364

During 2003, the Trust paid $1,748,932 (2002 - $1,235,872: 2001 - $589,169) of interest on long-term debt and bank indebtedness and $133,929 (2002 - $132,000: 2001 - $120,000) of capital taxes.

See accompanying notes to consolidated financial statements

Enterra Energy Trust

Notes to Consolidated Financial Statements

For the Years Ended December 31, 2003, 2002 and 2001

(Expressed in Canadian Dollars)

1. Structure of the Trust and basis of presentation

Enterra Energy Trust ("the Trust") was established on November 25, 2003 under a Plan of Arrangement involving the Trust, Enterra Energy Corp. ("Enterra"), Big Horn Resources Ltd. ("Big Horn"), Enterra Production Partnership and Enterra Saskatchewan Ltd. ("Plan of Arrangement"). The Trust is an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a trust indenture (the "Trust Indenture"). The beneficiaries of the Trust are the holders of the Trust Units (the "Unitholders").

Under the Plan of Arrangement, the shareholders of Enterra exchanged their shares for two Trust Units of the Trust, which will pay monthly distributions, or two Exchangeable Shares which may be exchanged into units of the Trust. Under the Plan of Arrangement, Enterra Energy Corp. (the "Company") became a wholly-owned subsidiary of the Trust, through amalgamation of Enterra, Big Horn Resources Ltd. and Enterra Saskatchewan Ltd on November 25, 2003. The Company holds, on behalf of the Trust, all the active oil and gas assets previously held by Enterra.

Prior to the implementation of the Plan of Arrangement on November 25, 2003, the consolidated financial statements included the accounts of Enterra and its subsidiaries. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor entity to Enterra. Accordingly, these consolidated financial statements reflect the financial position, results of operations and cash flows as if the Trust, (together with its wholly owned subsidiary, the Company), had always carried on the business formerly carried on by Enterra with all assets and liabilities recorded at the carrying values of Enterra.

Restructuring costs associated with the Plan of Arrangement included legal, accounting and advisory costs of $2,057,075 and employee bonus payments of $3,699,000.

The restructuring charges in 2001 in the amount of $929,037 related to the reorganization of Enterra by way of Plan of Arrangement in conjunction with the acquisition of Big Horn as set out in note 3.

2. Significant accounting policies

These consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The impact of significant differences between Canadian GAAP and U.S. GAAP on these consolidated financial statements is disclosed in note 17. These consolidated financial statements include the accounts of the Trust, its wholly owned subsidiary Enterra Energy Corp and its 100% partnership interest in Enterra Production Partnership (collectively the "Trust" for purposes of the following notes to the financial statements). All material intercompany accounts and transactions have been eliminated. Substantially all exploration, development and production activities related to the Trust s oil and gas business are conducted jointly with others and the accounts reflect only the Trust s proportionate interest.

(a) Petroleum and natural gas properties

The Trust follows the "full cost" method of accounting for petroleum and natural gas properties. All costs related to the exploration for and the development of oil and gas reserves are capitalized into a single cost centre representing the Trust s activity which is undertaken exclusively in Canada. Costs capitalized include land acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling productive and non-productive wells. Proceeds from the disposal of properties are applied as a reduction of cost without recognition of a gain or loss except where such disposals would result in a major change in the depletion rate.

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2. Significant accounting policies (Continued)

Capitalized costs are depleted and depreciated using the unit-of-production method based on the estimated gross proven oil and natural gas reserves before royalties as determined by independent engineers. Units of natural gas are converted into barrels of equivalents on a relative energy content basis. Costs related to unproved properties are excluded from the costs subject to depletion until it is determined whether or not proved reserves exist or if impairment has occurred.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, capitalized costs, net of accumulated depletion and depreciation, are limited to estimated future net revenues from proven reserves, based on year-end prices, undiscounted, plus the net costs of major development projects and unproved properties, less estimated future abandonment and site restoration costs, general and administrative expenses, financing costs and income taxes. Any accumulated costs in excess of the calculated ceiling test are charged to operations as a provision for impairment.

Estimated future abandonment and site restoration costs are provided for over the life of proven reserves on a unit-of-production basis. The annual charge is included in depletion and depreciation expense and actual abandonment and site restoration costs are charged to the provision as incurred. The amounts recorded for depletion and depreciation and the provision for future abandonment and site restoration costs are based on estimates of proven reserves and future costs. The recoverable value of capital assets is based on a number of factors including the estimated proven reserves and future costs. By their nature, these estimates are subject to measurement uncertainty and the impact on financial statements of future periods could be material.

(b) Income taxes

The Trust follows the liability method of accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities) and are measured using the currently enacted, or substantially enacted, tax rates and laws expected to apply when these differences reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized. Income tax expense or benefit is the sum of the Trust s provision for current income taxes and the difference between the opening and ending balances of the future income tax assets and liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. As the Trust allocates all of its taxable income to the unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense has been made in the Trust.

In the Trust structure, payments are made between the Company and the Trust, which results in the transferring of taxable income from the Company to individual unitholders. These payments may reduce future income tax liabilities previously reported by the Company, which would be recognized as a recovery of income tax in the period incurred.

(c) Financial instruments

The estimated fair value of all financial instruments is based on quoted market prices and if not available, on estimates from third-party brokers or dealers. The Trust uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, as described in note 13. Hedge accounting is used when there is a high degree of correlation between price movements in the derivative instrument and the item designated as being hedged. The Trust recognizes gains and losses in the same period as the hedged item. If effective correlation ceases, hedge accounting is terminated and future changes in the market value of the derivative instruments are included as gains or losses in income in the period of change.

2. Significant accounting policies (Continued)

(d) Estimates and assumptions

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and the disclosure of contingent assets and liabilities at the dates of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Actual results could differ from those estimates.

(e) Per unit amounts

Per unit amounts are calculated using the weighted average number of units (or common shares to November 24, 2003) and reflect the two for one exchange ratio pursuant to the Plan of Arrangement.

The Trust follows the treasury stock method to determine the dilutive effect of options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

(f) Unit-based compensation plan

Compensation cost for employees and directors is measured based on the intrinsic value of the award at the date of the grant and is recognized over the vesting period. Compensation cost for consultants is based on fair value and is expensed in the financial statements with the offset to contributed surplus. Any consideration received by the Trust on exercise of the unit rights will be credited to unitholders capital. Effective January 14, 2004, the Trust adopted a unit based compensation plan for employees, directors and consultants of the Trust.

Effective January 1, 2002 Enterra prospectively adopted the new recommendations of the CICA with respect to the accounting for stock-based compensation and other stock-based payments. In accordance with the new standard, the Trust elected to continue its policy that no compensation be recorded on the granting of employee options and consideration paid on the exercise of such options be recorded as shareholders capital. In addition, the new standard requires a fair value based method of accounting for other stock-based payments. See notes 9(f) and 9(g) for additional information with regard to the methods and assumptions used in calculating the fair value of stock-based compensation.

(g) Revenue recognition

Revenue from the sale of oil and gas is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation and production based royalty expenses are recognized in the same period in which the related revenue is earned and recorded and are classified as part of production expenses.

(h) Deferred financing charges

Deferred financing charges include costs related to the proposed financing mentioned in note 9(h) and costs related to capital leases due October 1, 2007 as described in note 7. These costs include professional and consulting fees, travel costs, legal and accounting, and also include the $125,000 described in note 9(h). These costs are amortized over the remaining life of their related financial instruments.

2. Significant accounting policies (Continued)

(i) Comparative figures

The presentation of certain figures of the previous year has been changed to conform with the presentation adopted for the current year.

3. Business combination

Effective August 1, 2001 Enterra acquired 100% of the issued and outstanding shares of Big Horn Resources Ltd. Details of the acquisition are as follows:

Assets acquired:	
Current assets, excluding cash	$2,841,106
Property and equipment	46,874,349
	49,715,455
Liabilities assumed:	
Current liabilities	2,428,687
Bank indebtedness	8,950,000
Provision for future abandonment and site restoration costs	280,274
Future income tax liability	11,309,464
	22,968,425
Net non-cash assets acquired	26,747,030
Cash acquired	37,599
	$26,784,629
Consideration:	
Cash	$2,227,647
Preferred shares (7,418,336 issued)	6,305,586
Common shares (3,496,436 issued)	18,251,396
	$26,784,629

The consideration value attributed to the common shares contemplates an element related to the former stock options of Big Horn that were exchanged for stock options of Enterra. However, this element was not considered significant for separate reporting.

4. Property and equipment

	Cost	Accumulated depletion and depreciation	2003 Net
Petroleum and natural gas properties	$145,691,316	$41,601,024	$104,090,292
Office furniture and equipment	1,358,421	627,428	730,993
	$147,049,737	$42,228,452	$104,821,285

	Cost	Accumulated depletion and depreciation	2004 Net
Petroleum and natural gas properties	$112,657,277	$18,897,024	$93,760,253
Office furniture and equipment	1,077,988	483,928	594,060
	$113,735,265	$19,380,952	$94,354,313

In conducting its ceiling test evaluation for 2003 the Trust followed generally accepted accounting principles based on prices at December 31, 2003 of $34.07 per bbl of oil (2002 - $45.89) and $6.03 per mcf of gas (2002 - $5.49). No write-down was required for 2003, 2002 or 2001.

Included in petroleum and natural gas properties are assets acquired and pledged under capital lease agreements with a cost base of $5,217,500 and net book value of $4,267,600 (2002 - $5,217,500 and $5,065,100).

Included in the cost of the petroleum and natural gas properties are amounts for capitalized general and administrative expenses. These amounts were $1,787,000 in 2003 (2002 - $1,450,900: 2001 - $729,400).

At December 31, 2003 costs of undeveloped land of $5,037,000 (2002 - $3,967,000) were excluded from the calculation of depletion expense.

The Trust estimates future abandonment and site restoration costs to be $3,240,000 at December 31, 2003 (2002 - $4,114,000) of which $1,529,244 (2002 - $934,857) has been accrued as a liability. The provision for site restoration and abandonment totaling $704,800 (2002 - $232,500: 2001 - $242,000) is included as part of depreciation, depletion and site restoration expense.

5. Accounts payable and accrued liabilities

	2003	2002
Trade accounts payable	**$7,808,042**	$13,762,437
Other	**4,400,348**	6,898,568
	$12,208,390	$20,661,005

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6. Bank indebtedness

Bank indebtedness represents the outstanding balance under a line of credit of $34,650,000 (2002 - $26,700,000). Drawings bear interest at 0.25% above the bank s prime lending rate (December 31, 2003 - 4.50%). Security is provided by a first charge over all of the Trust s assets. The balance is repayable on demand. While the loan is due on demand, the Trust is not subject to scheduled repayments. Subsequent to year end, the line of credit was increased to $39,650,000.

7. Long-term debt

Description	**2003**	2002
Capital lease bearing interest at 8.605%, repayable monthly at $88,802 plus applicable taxes. The lease term is for 60 months, due October 1, 2007, with a purchase option of $1,000,000 and secured by the related equipment.	**$4,125,006**	$4,747,775
Capital lease bearing interest at 12.15%, repayable monthly at $4,448 plus applicable taxes. The lease term is 24 months due December 19, 2004 with a purchase option of $100 and secured by the related equipment.	**43,542**	91,042
Note payable bearing interest at 8%, repayable monthly at $7,190. The lease term is 15 months due December 20, 2003.	**-**	82,781
	4,168,548	4,921,598

Less current portion	**(782,930)**	(808,917)
	$3,385,618	$4,112,681

Interest expense includes $358,413 (2002 - $106,174, 2001 - $nil) related to long-term debt.

8. Income taxes

The income tax provision is calculated by applying Canadian federal and provincial statutory tax rates to pre-tax income with adjustments as set out in the following table:

	2003	2002	2001
Earnings before income taxes	$7,079,030	$6,020,401	$2,299,055
Combined federal and provincial income tax rate	40.75%	42.12%	42.60%
Computed income tax provision	2,884,705	2,535,793	979,397
Increase (decrease) resulting from:			
Resource allowance	(3,259,987)	(1,627,200)	(1,211,828)
Non-deductible Crown royalties, net of ARTC	5,412,264	1,313,089	781,332
Value of warrants expensed for book purposes	114,772	-	-
Interest component of trust distributions	(722,894)	-	-
Effect of change in tax pools	(1,247,424)	-	-
Effect of reduction in corporate tax rates	(1,579,285)	-	-
Non-taxable portion of capital gain	-	(1,310,552)	-
Capital taxes	133,929	132,000	120,000
Other	339,148	(130)	13,099
	$2,075,228	$1,043,000	$682,000

8. Income taxes (Continued)

The components of the net future income tax liability at December 31 were as follows:

	2003	2002
Future income tax assets:		
Share issue costs	$398,868	$647,597
Future abandonment and site restoration	529,528	295,321
Deferred gain	-	75,015
	928,396	1,017,933
Future income tax liabilities:		
Property, plant and equipment	13,083,004	11,052,168
Net future income tax liability	$14,011,400	$12,070,101

At December 31, 2003 the Company had approximately $66.4 million (2002 - $62.6 million and 2001 - $43.2 million) of tax pools available to reduce future taxable income.

9. Unitholders Equity

(a) Authorized Trust Units

An unlimited number of Trust Units may be issued pursuant to the Trust Indenture.

(b) Issued Trust Units

	Number of Units/Shares	Amount
Balance, December 31, 2000	9,190,278	$5,031,846
Issued upon exercise of options	87,000	99,450
Issued pursuant to public offerings	2,070,000	7,081,024
Issued on acquisition of property and equipment	426,094	1,300,000
Issued on acquisition of Big Horn Resources Ltd. (note 3)	6,992,872	18,251,396

Shares repurchased	(465,000)	(753,300)
Issue costs incurred, net of income tax benefit of $1,118,251	-	(1,442,153)
Balance, December 31, 2001	18,301,244	$29,568,263
Issued upon exercise of options	89,022	171,127
Shares repurchased	(37,616)	(74,315)
Balance, December 31, 2002	18,352,650	$29,665,075
Issued upon exercise of options and warrants	2,598,906	6,283,461
Contributed surplus transferred on exercise of warrants	-	346,677
Issued pursuant to Plan of Arrangement:		
Shares exchanged for Exchangeable shares and cancelled	(2,000,000)	(3,464,679)
Shares exchanged for Trust Units and cancelled	(18,951,556)	(32,830,534)
Trust Units issued	18,951,556	32,830,534
Issued for Exchangeable Shares	4,404	7,629
Balance, December 31, 2003	18,955,960	$32,838,163

9. Unitholders Equity (Continued)

Pursuant to the Plan of Arrangement, 18,951,556 Trust Units and 2,000,000 Exchangeable Shares were issued on November 25, 2003 at a two for one exchange ratio and upon cancellation of all outstanding common shares of Enterra. The consideration attributed to the Trust Units and the Exchangeable Shares was the relative proportion of the carrying value of the common shares of Enterra prior to the exchange. Prior to December 31, 2003, 4,404 exchangeable shares were converted to Trust Units. The prior years number of shares issued in the share tables above have been restated to reflect the two for one exchange ratio under the Plan of Arrangement.

(c) Issued Exchangeable Shares

	Number of Units	**Amount**
Issued pursuant to Plan of Arrangement	2,000,000	$3,464,679
Exchanged for Trust Units	(4,404)	(7,629)
Balance, December 31, 2003	1,995,596	$3,457,050

The Exchangeable Shares of the Company are convertible at any time into Trust Units (at the option of the holder) based on the exchange ratio. The exchange ratio is increased monthly based on the cash distribution paid on the Trust

Units divided by the ten day weighted average unit price preceding the distribution payment date. During the period of November 25 to December 31, 2003, a total of 4,404 Exchangeable Shares were converted into 4,404 Trust Units at a one for one exchange ratio prevailing at the time. The exchange ratio at the time of issuance on November 25, 2003 and at December 31, 2003 was one Trust Unit for each Exchangeable Share. Cash distributions are not paid on the Exchangeable Shares. On the third anniversary of the issuance of the Exchangeable Shares, subject to extension of such date by the Board of Directors of the Trust, or at the Trust s option when the aggregate number of issued and outstanding Exchangeable Shares is less than 1,000,000, the Exchangeable Shares will be redeemed for Trust Units at a redemption price per exchangeable share equal to the value of that number of Trust Units equal to the exchange ratio as at that Redemption Date. The Exchangeable Shares of the Company are not listed for trading on an exchange.

(d) Contributed surplus

Balance at January 1, 2002	$ -
Value assigned to 100,000 warrants described in note 9(h)	125,000
Loss related to shares repurchased during year	(59,971)
Balance at December 31, 2002	65,029
Value assigned to 200,000 warrants described in note 9(h)	281,648
Transfer on exercise of warrants (note 9(b))	(346,677)
Balance at December 31, 2003	$ -

9. Unitholders Equity (Continued)

(e) Options

Enterra granted options to purchase common shares to directors, officers, employees and consultants. Each option permitted the holder to purchase one common share of Enterra at the stated exercise price. All options vest over 4 years and are exercisable on a cumulative basis over 5 years. At the time of grant, the exercise price is equal to the market price. The following options have been granted:

	Number of Options	Weighted-average exercise price
Balance at December 31, 2000	430,500	$5.76
Options granted	990,000	$4.41
Options exercised	(43,500)	$2.29

Options cancelled	(577,000)	$6.15
Balance at December 31, 2001	800,000	$4.00
Options granted	232,000	$5.30
Options exercised	(44,511)	$3.84
Options cancelled	(115,786)	$4.03
Balance at December 31, 2002	871,703	$4.35
Options granted	31,500	$15.74
Options exercised	(899,453)	$4.74
Options cancelled	(3,750)	$4.41
Balance at December 31, 2003	-	-

Of the 31,500 options granted during 2003, 6,000 were granted to non-employees (2002 55,000). Compensation expense related to these options amounted to $46,000 (2002 - $18,000) under the fair value based method of accounting. Total options of 899,453 vested and were exercised at prices ranging from $4.00 to $18.58 pursuant to the Plan of Arrangement.

(f) Estimated fair value of stock options

The estimated fair value of options was determined using the Black-Scholes model under the following assumptions:

	2003	2002	2001
Weighted-average fair value of options granted ($/option)	**$ 7.75**	$2.83	$0.76
Risk-free interest rate (%)	**5.0**	5.0	5.0
Estimated hold period prior to exercise (years)	**5**	5	5
Expected volatility in the price of Enterra s shares (%)	**50**	55	30

9. Unitholders Equity (Continued)

(g) Pro forma net income fair value based method of accounting for options

The following shows pro forma net income and earnings per unit had the fair-value based method of accounting been applied to options issued in 2003, 2002 and 2001:

	2003	2002	2001
Net earnings, as reported (in 000 s)	**$ 5,004**	$ 4,977	$ 1,617
Less: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	**(631)**	(47)	(27)
Pro forma net earnings	**$ 4,373**	$ 4,930	$ 1,590
Earnings per Unit/Share			
Basic as reported	$ 0.26	$ 0.27	$ 0.12
Basic pro forma	$ 0.21	$ 0.27	$ 0.11
Diluted as reported	$ 0.26	$ 0.26	$ 0.12
Diluted pro forma	$ 0.21	$ 0.26	$ 0.11

(h) Warrants

	Number of Warrants	**Weighted Average Price**
Balance, December 31, 2000	-	-
Issued pursuant to public offering	1,000,000	US$3.50
Issued pursuant to underwriters agreement	100,000	US$5.40
Balance, December 31, 2001	1,100,000	US$3.67
Expired	(1,000,000)	US$3.50
Issued pursuant to debt financing	100,000	US$2.60
Balance, December 31, 2002	200,000	US$4.00
Issued pursuant to debt financing agreement amendment	200,000	US$3.65
Exercised pursuant to Plan of Arrangement	(400,000)	US$3.83
Balance, December 31, 2003	-	-

9. Unitholders Equity (Continued)

(h) Warrants (Continued)

On January 17, 2001, the Company completed a secondary public offering in the United States. The offering consisted of 1,000,000 units of one common share and one share purchase warrant for U.S. $4.55 per unit. The share purchase warrants were exercisable at US$ 3.50 per share. They expired on May 17, 2002. The 100,000 share purchase warrants related to the underwriters agreement were exercisable at U.S. $5.40 per share starting January 16, 2002 and could be exercised for a four year period thereafter. On March 28, 2002 the Company agreed to issue 300,000 share purchase warrants to an arm s length U.S.-based consulting firm in connection with a potential debt financing in the United States. The warrants had a two-year term and were subject to different exercise prices (100,000 warrants at US$2.60, 100,000 at US$3.30 and 100,000 at US$4.00). The US$2.60 warrants vested upon the execution in May 2002 of a non-binding letter of intent relating to the proposed financing. A value of $125,000 was assigned to the 100,000 warrants at US$2.60. This value was determined using the Black-Scholes Option Pricing model using an interest rate of 5% and a volatility factor of 50%. The $125,000 was credited to the Company s contributed surplus. The US$3.30 and US$4.00 warrants were to vest only on the successful closing and funding of the proposed financing. At the May, 2003 shareholders meeting, the terms were amended to provide for immediate vesting of these warrants as of the April 16, 2002 date of the agreement. The value of $281,648 was expensed in the current year and included in note 9(d).

10. Reconciliation of Earnings per Share Calculations

For the year ended December 31, 2003 the weighted average number of units outstanding was 18,953,968. There are no options outstanding as at December 31, 2003 and therefore no dilution to earnings per unit for 2003. Prior years number of shares and per share calculations have been restated to reflect the two for one exchange of units for common shares under the Plan of Arrangement.

For the year ended December 31, 2002

	Net Earnings	**Weighted Average Shares Outstanding**	**Per Share**
Basic	$4,977,401	18,308,982	$0.27
Options and warrants assumed exercised		1,607,998	
Shares assumed purchased		(1,091,766)	
Diluted	$4,977,401	18,825,214	$0.26

Excluded from the above calculation are 61,000 options, which were "out-of-the-money" in 2002.

For the year ended December 31, 2001

	Net Earnings	Weighted Average Shares Outstanding	Per Share
Basic	$1,617,055	13,984,786	$0.12
Options and warrants assumed exercised		92,054	
Shares assumed purchased		(81,826)	
Diluted	$1,617,055	13,995,014	$0.12

11. Series 1 preferred shares

On March 26, 2002 the Company purchased 6,123,870 of its Series 1 preferred shares for $2.3 million, resulting in a gain on redemption of $2,905,290. The purchase was paid for with cash of $1,750,000 and a note payable of $550,000. This note was repaid for $325,000 on August 15, 2002 resulting in an additional gain, net of legal costs, of $206,181. During 2003, the remaining 749,047 shares were redeemed for $636,690 ($0.85 per share). A dividend of $33,428 (2002 - $22,549) was paid on the preferred shares before their redemption. This amount is included in interest expense. At December 31, 2003 there were no Series 1 preferred shares outstanding (2002 749,047).

12. Financial instruments

The Trust s financial instruments recognized on the consolidated balance sheets include accounts receivable, accounts payable and accrued liabilities, distributions payable, income taxes payable, bank indebtedness and long-term debt. The fair values of financial instruments other than bank debt approximates their carrying amounts due to the short term nature of the instruments. The carrying value of bank indebtedness approximates its fair value due to floating interest terms; the fair value of the long-term debt approximates carrying value due to current rates for comparable terms of long-term debt.

Due to the nature of its operation, the Trust is exposed to fluctuations in commodity prices, foreign-currency exchange rates, interest rates and credit risk. The Trust recognizes these risks and manages its operations to minimize the exposure to the extent practical and, to a lesser extent, using derivative instruments. The Trust uses non-exchange traded forwards, swaps and options, which may be settled in cash or by delivery of the physical commodity. Management monitors the Trust s exposure to the above risks and regularly reviews its derivative activities and all outstanding positions.

(a) Commodity price risks

The Trust s most significant market risk exposure relates to crude oil prices fluctuation. Crude oil prices and quality differentials are influenced by worldwide factors such as OPEC actions, political events and supply and demand fundamentals.

To a lesser extent the Trust is also exposed to natural gas price movements. Natural gas prices are generally influenced by North American supply and demand, and to a lesser extent local market conditions.

(b) Foreign currency exchange risk

The Trust is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices.

(c) Credit risk

A substantial portion of the Trust s accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Trust s natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment.

(d) Interest rate risk

Interest rate risk exists principally with respect to the Trust's indebtedness that bears interest at floating rates. At December 31, 2003, the Trust had $33,959,733 of indebtedness bearing interest at floating rates and $4,168,548 of long-term debt bearing interest at fixed rates.

13. Hedging contracts

Enterra entered into the following hedges to minimize its exposure to fluctuations in commodity prices relating to its future sales of crude oil and gas. The contracts are as follows:

(a) Enterra entered into a physical zero cost collar arrangement during 2001 which provided a floor price of US$20 per barrel and a ceiling price of US$24 per barrel for 500 barrels of oil per day. The contract was effective from November 1, 2001 through April 30, 2002.

(b) In July 2002, Enterra entered into a physical zero cost collar arrangement with a floor price of US$22 per barrel and a ceiling price of US$28 per barrel for 500 barrels of oil per day. The contract was effective from October 1, 2002 through March 31, 2003.

(c) In July 2002, Enterra entered into two contracts to deliver natural gas. One was for 1,500 mcf per day, priced at Cdn$4.60 per mcf. The other was for 1,500 mcf per day, priced at Cdn$4.45 per mcf. Both contracts were effective from November 1, 2002 through March 31, 2003

(d) In February of 2003 Enterra entered into several contracts to deliver 2,000 barrels of oil per day for the period from April 1, 2003 to December 31, 2003. The prices and volumes are as follows:

Volumes (in barrels per day)	Price (in US dollars)
1,000	US$29.60
250	US$29.71
250	US$29.50
500	US$29.80

(e) In the third quarter of 2003, Enterra entered into contracts to deliver 2,000 barrels of oil per day from January 1, 2004 to June 30, 2004, 500 barrels at US$26.68 to be delivered physically and 500 barrels at US$26.75 and 1,000 barrels at Cdn$38.50 to be delivered financially. At December 31, 2003 the contracts had an estimated negative fair market value of $1,626,207.

(f) On January 23, 2004, the Trust entered into contracts to deliver 1,000 barrels of oil per day from July 1, 2004 to December 31, 2004 at Cdn$40.50.

Effective January 31, 2001, Enterra settled a fixed price contract eliminating the requirement to deliver set physical quantities of oil at fixed prices. Upon the cancellation of the contract Enterra received approximately $1,680,000, which was recognized over the term of the contract. At December 31, 2003 the remaining deferred gain related to this settlement was nil (2002 - $237,463).

14. Commitments

The Trust has commitments for the following payments over the next five years:

	2004	2005	2006	2007	Thereafter 2008
Minimum capital lease payments	$786,889	$809,538	$877,697	$1,702,342	$ -
Imputed interest	332,105	260,530	187,923	96,873	-
Capital lease obligations	1,118,994	1,070,068	1,065,620	1,799,215	-
Rental payments re-office space	460,447	467,717	414,770	309,990	640,920
	$1,579,441	$1,537,785	$1,480,390	$2,109,205	$640,920

During 2003 total rental expense was $299,312 (2002 - $240,555, 2001 - $167,545).

15. Guarantees

In the normal course of operations, the Trust may provide indemnification in conjunction with certain transactions. The terms of these indemnification obligations range in duration and often are not explicitly defined. In many cases, there is no maximum limit on these indemnification obligations and the overall maximum amount of the obligation under such indemnification obligations cannot be reasonably estimated. The Trust has not made significant payments under these and there are no material indemnification obligations at year end.

16. Subsequent events

(a) On January 16, 2004 the Trust entered into a financing agreement whereby the Trust will issue 1,650,000 Trust Units at a price of US$10.00 per unit for gross proceeds of US$16,500,000. Payment will be received pending registration of the units.

(b) On January 30, 2004 the Trust closed an acquisition of petroleum and natural gas properties in East Central Alberta for $19,847,000. At December 31, 2003, the Trust had made a refundable deposit on the property purchased in the amount of $2,015,000. Results from operations will be included in the Trust from the closing date.

(c) On February 20, 2004 the Trust completed a private placement of 1,049,400 Trust Units at a price of US$11.25 per unit for gross proceeds of US$11,805,750 (US$10,265,463 net of financing costs).

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America

The Trust s consolidated financial statements have been prepared in Canadian Dollars and in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"), which differ in some respects from those in the United States of America ("U.S. GAAP"). Any differences in accounting principles as they pertain to the accompanying consolidated financial statements were insignificant except as described below:

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America (Continued)

(a) Property and equipment

The Trust performs a cost recovery ceiling test which limits net capitalized costs to the undiscounted estimated future net revenue from proven oil and gas reserves plus the cost of unproven properties less impairment, using year-end prices or average prices in that year, if appropriate. In addition, the value is further limited by including financing costs, administration expenses, future abandonment and site restoration costs and income taxes. Under U.S. GAAP, companies using the "full cost" method of accounting for oil and gas producing activities perform a ceiling test using discounted estimated future net revenue from proven oil and gas reserves using a discount factor of 10%. Prices used in the U.S. GAAP ceiling tests performed for this reconciliation were those in effect at the applicable period end. Financing and administration costs are excluded from the calculation under U.S. GAAP. At December 31, 2001 Enterra realized a U.S. GAAP ceiling test write-down of $28.7 million ($17.5 million after tax). There was no such write-down at December 31, 2003 or December 31, 2002. As a result of the 2001 write-down, the 2003 depletion expense under U.S. GAAP was lower by $5.7 million ($3.4 million after tax and in 2002 $3.6 million ($2.1 million after tax).

(b) Financial instruments

FAS 133 requires the Trust to recognize all derivative instruments (included derivative instruments embedded in other contracts) as defined, in the balance sheet as either an asset or a liability measured at fair value and requires that changes in fair value be recognized currently in income unless specific hedge accounting criteria are met. There are no similar standards in Canadian GAAP at this time. Changes in the fair value of derivatives are recognized in earnings unless specific hedge criteria are met. The negative fair value of such contracts at December 31, 2003 was $958,359 (2002 - $nil).

Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs and requires that an entity formally document, designate and assess effectiveness of derivative instruments that receive hedge accounting treatment. Upon adoption, the Trust did not designate its hedging relationships. As a result, the Trust is required to use fair value accounting for its derivative instruments for U.S. GAAP and the change in fair value of these contracts has been reported in income.

The Trust routinely enters into commodity contracts to minimize its exposure to fluctuations in commodity prices relating to its future sales of crude oil. Such contracts often meet the criteria of FAS 133 as derivatives but are generally eligible for the normal purchase and sale exception under FAS 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities   An Amendment of FAS 133". Contracts that meet the criteria of this exception are not recognized on the balance sheet as either an asset or a liability measured at fair value. The fair value of such contracts at December 31, 2003 was $667,848 (2002 - $585,000).

At December 31, 2002, under Canadian GAAP, the Trust had a deferred gain of $237,463 (2001 - $761,302) resulting from the settlement of a fixed price contract, which is being amortized over the term of the contract. Under U.S. GAAP, this gain, net of related income taxes, would be included in income as it did not qualify for hedge accounting under FAS 133.

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America (Continued)

(c) Stock-based compensation

Under U.S. GAAP, FAS 123 establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. During 2001, the Company granted 119,500 stock options to non-employees. The value associated with these stock options was $90,924 for U.S. GAAP purposes. The fair value of each option granted was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions: risk-free interest rate of 5%, expected volatility of 30% and expected life of five years. After January 1, 2002, stock options issued to non-employees resulted in the same accounting treatment under both Canadian and U.S. GAAP.

The following table illustrates the effect on net income and earnings per unit if the Trust had applied the fair value recognition provisions of FAS 123 to stock-based employee compensation.

	2003	2002	2001
Net earnings, as reported (in 000 s)	**$ 6,510**	$ 6,748	$ (15,534)
Less: Total stock-based employee compensation expense determined under fair value based method for all awards net of related tax effects	**(737)**	(110)	(55)
Pro forma net earnings	**$ (5,773)**	$ 6,638	$ (15,589)
Earnings per unit			
Basic - as reported	$ 0.34	$ 0.37	$ (1.11)
Basic - pro forma	$ 0.30	$ 0.36	$ (1.11)
Diluted - as reported	$0.34	$ 0.36	$ (1.11)
Diluted - pro forma	$ 0.30	$ 0.35	$ (1.11)

(d) Cash flows

Future abandonment and site restoration costs are presented as investing activities but under FAS 143 they would be classified as operating activity and included in the reconciliation of beginning and ending asset retirement obligations.

(e) Earnings

Interest and amortization of deferred financing charges would be presented in the non-operating section of the statement of earnings under U.S. GAAP while restructuring charges would be presented in the operating section of the statement of earnings for all periods presented.

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America (Continued)

(f) Comprehensive Income

There are no items that would be part of Comprehensive Income other than net income.

(g) Asset Retirement Obligations

For Canadian reporting purposes, the Trust provides for site restoration abandonment on a unit of production basis over the life of the Trust s proven reserves. Changes to Canadian accounting standards, effective January 1, 2004, are expected to eliminate this GAAP difference in future years. Under US GAAP the provision for future abandonment and site restoration costs of $1.5 million (2002 - $0.9 million) is a reduction of property and equipment.

Effective January 1, 2003 the Trust adopted Financial Accounting Standards Board (FASB) Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) for US GAAP reporting purposes. FAS 143 requires recognition of a liability for the future retirement obligations associated with property, plant and equipment, which includes oil and gas wells and facilities. These obligations, which generally relate to dismantlement and site restoration, are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the Trust expects to settle the retirement obligation.

Had FAS 143 been applied during all periods presented, the results would have been reported as follows:

January, 2002	$1,913,161
December 31, 2002	$3,090,389
December 31, 2003	$2,188,052

The change in the asset retirement obligation since the beginning of the year is as follows:

	2003
Asset Retirement Obligation at January 1	$3,090,389

Obligation incurred	744,422
Abandonment expenditures	(5,414)
Property disposition	(1,753,446)
Accretion	112,101
Revision in estimate	-
Effect of foreign exchange	-
Asset Retirement Obligation at December 31	$2,188,052

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America (Continued)

(g) Asset Retirement Obligations (Continued)

This change in accounting policy has been reported as a cumulative effect adjustment in the Consolidated Statement of Earnings as a loss of $1,148,165, net of income taxes of $607,976. Under the former US GAAP accounting rules, the Trust s results would have been as follows:

	2002	**2001**
Net earnings - US GAAP		
As reported	$6,748,492	$(15,534,391)
Cumulative effect of change in accounting principle		
Depreciation, depletion, amortization and accretion, net	(202,284)	(215,936)
Adjusted	$6,546,208	$(15,750,327)
Earnings per unit/share		
Basic as reported	$0.37	($1.11)
Adjusted	$0.36	($1.13)
Diluted as reported	$0.36	($1.11)
Adjusted	$0.35	($1.13)

(h) Balance sheets

The adjustments using U.S. GAAP would result in the following changes to the consolidated balance sheets of the Trust:

	2003		2002	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP
Assets				
Current assets	**$11,285,060**	**$11,285,060**	$8,078,752	$8,078,752
Capital assets (a)(g)	**104,821,285**	**84,288,022**	94,354,313	68,307,526
Deferred financing charges	**123,208**	**123,208**	284,040	284,040
	$116,229,553	**$95,696,290**	$102,717,105	$76,670,318
Liabilities				
Current liabilities	**$49,522,455**	**$49,522,455**	$46,061,986	$46,061,986
Long-term debt	**3,385,618**	**3,385,618**	4,112,681	4,112,681
Financial derivative liabilities (b)	**-**	**958,359**	-	-
Future income taxes (a) (b) (c)	**14,011,400**	**5,644,691**	12,070,101	2,485,695
Asset retirement obligation provision (g)	**1,529,244**	**2,188,052**	934,857	-
Deferred gain (b)	**-**	**-**	237,463	-
Series 1 preferred shares	**-**	**-**	636,690	636,690
	68,448,717	**61,699,175**	64,053,778	53,297,052

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America (Continued)

(h) Balance sheets (Continued)

	2003		2002	
	Canadian GAAP	**U.S. GAAP**	Canadian GAAP	U.S. GAAP

Unitholders equity				
Unitholders capital				
Authorized unlimited number of Trust Units (2002 unlimited number of common shares)				
Issued - 2003 -18,955,960 units				
- 2002 - 18,352,650 shares	**32,838,163**	**32,928,457**	29,665,075	29,665,075
Exchangeable shares 1,995,596	**3,457,050**	**3,457,050**	-	-
Contributed surplus	**-**	**-**	65,029	155,323
Accumulated earnings (deficit)	**13,937,025**	**63,010**	8,933,223	(6,447,132)
Accumulated distributions	**(2,451,402)**	**(2,451,402)**	-	-
	$47,780,836	**$33,997,115**	$38,663,327	23,373,266
	$116,229,553	**$95,696,290**	$102,717,105	$76,670,318

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America (Continued)

(i) Income statements:

The adjustments using U.S. GAAP would result in the following changes to the consolidated financial statements of the Trust:

	2003	2002	2001
Net earnings (loss) under Canadian GAAP	**$5,003,802**	$4,977,401	$1,617,055
Adjustments:			
Full cost accounting (a)	-	-	(28,695,705)
Related income taxes	-	-	11,159,101
Hedging gain (b)	**(237,463)**	(523,839)	761,302

Related income taxes	**96,766**	220,641	(324,315)
Depletion expense (a)	**5,676,000**	3,583,775	-
Related income taxes	**(2,312,970)**	(1,509,486)	-
Stock-based compensation (c)	**-**	-	(90,294)
Unrealized loss on financial instruments (b)	**(958,359)**	-	-
Related income taxes	**390,531**	-	38,465
Net earnings (loss) before undernoted items under U.S. GAAP	**7,658,307**	6,748,492	(15,534,391)
Cummulative effect of change in accounting principle FAS #143	**(1,756,141)**	-	-
Related income taxes	**607,976**	-	-
Net earnings (loss) under U.S. GAAP	**$6,510,142**	$6,748,492	($15,534,391)
Net earnings (loss) per unit/share before under noted items under US GAAP:			
Basic	**$0.40**	$0.37	($1.11)
Diluted	**$0.40**	$0.36	($1.11)
Net earnings (loss) per unit/share relating to change in accounting principle:			
Basic	**($0.06)**	$ -	$ -
Diluted	**($0.06)**	$ -	$ -
Net earnings (loss) per unit/share under US GAAP:			
Basic	**$0.34**	$0.37	($1.11)
Diluted	**$0.34**	$0.36	($1.11)

17. Differences between Generally Accepted Accounting Principles in Canada and the United States of America (Continued)

(j) Reconciliation of Earnings per Share Calculations

For the year ended December 31, 2003 the weighted average number of units outstanding was 18,953,968. There are no options outstanding as at December 31, 2003 and therefore no dilution to earnings per unit for 2003.

For the year ended December 31, 2002

	Net Earnings	Weighted Average Shares Outstanding	Per Share
Basic	$6,748,492	18,308,982	$0.37
Options and warrants assumed exercised		1,607,998	
Shares assumed purchased		(1,091,766)	
Diluted	$6,748,492	18,825,214	$0.36

For the year ended December 31, 2001

	Net Earnings	Weighted Average Shares Outstanding	Per Share
Basic	$(15,534,391)	13,984,786	$(1.11)
Options and warrants assumed exercised		92,054	
Shares assumed purchased		(81,826)	
Diluted	$(15,534,391)	13,995,014	$(1.11)

New Accounting Pronouncements

The following standards issued by the FASB do not impact us at this time:

(a) Interpretation No. 46, "Consolidation of Variable Interest Entities", effective for the Trust for the period ending December 31, 2004.

(b) FAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity", effective for financial statements issued after June 15, 2003.

(c) FAS No. 132 (revised 2003), "Employers Disclosures about Pensions and Other Post Retirements Benefits - an amendment of SFAS No. 87, 88 and 106", effective for financial statements issued after December 15, 2003.

(d) FAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", effective for contracts entered into or modified after June 30, 2003.

The Trust will continue to assess the applicability of these standards in the future.

Supplemental disclosure about Oil and Gas producing activities (unaudited)

The following oil and gas information is provided in accordance with the US Financial Accounting Standards Board Statement No. 69 "Disclosure About Oil and Gas Producing Activities". The Trust follows the full cost method of accounting.

(a) Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil producing activities, and related aggregate amounts of accumulated depreciation, depletion and amortization, at December 31, 2003 and 2002 follow:

	2003	2002
Capitalized costs		
Proved properties being amortized	**$112,219,344**	$80,137,875
Unproved properties not being amortized	**5,037,355**	3,966,828
Total capitalized costs	**117,256,699**	84,104,703
Less accumulated depletion, depreciation, future site restoration and amortization	**(32,968,677)**	(15,797,177)
Net capitalized costs	**$84,288,022**	$68,307,526

The following costs were incurred in oil and gas producing activities during the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
Property acquisition costs			
Proved properties	**$ -**	$512,338	$47,010,438

Unproved properties	**8,028,090**	3,643,053	3,182,644
Exploration costs	**765,505**	167,947	442,028
Development costs	**42,503,250**	31,557,918	11,781,390
Total costs incurred	**$51,296,845**	$35,881,256	$62,416,500

Supplemental disclosure about Oil and Gas producing activities (unaudited) (Continued)

(b) Reserves Quantity Information

Estimated net quantities of proved gas and oil (including condensate) reserves in Canada at December 31, 2003, 2002 and 2001, and changes in the reserves during those years, are shown in the two tables which follow.

	2003	2002	2001
Proved developed and undeveloped reserves Oil (mboe)			
At January 1	**5,234.2**	4,126.9	2,330.9
Changes in reserves:			
Extensions, discoveries and other additions	**2,266.6**	2,564.3	730.0
Revisions of previous estimates	**(457.9)**	(60.8)	4.9
Production	**(1,406.2)**	(533.0)	(582.2)
Purchases of oil in place	**113.4**	-	1,698.4
Sales of oil in place	**(600.8)**	(863.2)	(55.1)
At December 31	**5,149.3**	5,234.2	4,126.9
Proved developed reserves - Oil (mboe)			
At January 1	**3,951.7**	3,733.8	2,048.5
At December 31	**5,149.3**	3,951.7	3,733.8

	2003	2002	2001
Proved developed and undeveloped reserves Gas (mboe)			
At January 1	**2,174.4**	1,794.0	162.7
Changes in reserves			
Extensions, discoveries and other additions	**534.0**	938.5	494.8
Revisions of previous estimates	**(183.0)**	(175.7)	(270.7)
Production	**(427.0)**	(313.7)	(113.3)
Purchases of gas in place	**26.1**	-	1,578.6
Sales of gas in place	**(1,106.4)**	(68.7)	(58.1)
At December 31	**1,018.1**	2,174.4	1,794.0
Proved developed reserves - Gas (mboe)			
At January 1	**2,037.5**	1,650.2	162.7
At December 31	**1,018.1**	2,037.5	1,650.2

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Supplemental disclosure about Oil and Gas producing activities (unaudited) (Continued)

(c) Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

The following tabulation has been prepared in accordance with the FASB s rules for disclosure of a standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities owned by the Trust.

	2003	2002	2001
Future cash inflows (000 s)	$207,948	$309,953	$186,597
Less:			
Future development costs [(1)]	(200)	(7,487)	(4,802)
Future production costs	(83,332)	(109,383)	(83,314)
Future income tax expense	(15,174)	(54,959)	(23,550)
Future cash flows	109,242	138,124	74,931
Less annual discount (10% a year)	(18,683)	(31,453)	(22,554)

Standardized measure of discounted future net cash flows	$90,559	$106,671	$52,377

(1)

Amounts exclude the effect of derivative instruments designated as hedges of future sales of production at year end.

In the foregoing determination of future cash inflows, sales prices for gas and oil were based on contractual arrangements or market prices at year-end. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year end, assuming the continuation of existing economic conditions. Future income taxes were computed by applying the appropriate year-end or future statutory tax rate to future pretax net cash flows, less the tax basis of the properties involved, and giving effect to tax deductions, permanent differences and tax credits.

It is not intended that the FASB s standardized measure of discounted future net cash flows represent the fair market value of the Trust s proved reserves. The Trust cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10 percent discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

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Supplemental disclosure about Oil and Gas producing activities (unaudited) (Continued)

The following tabulation is a summary of changes between the total standardized measure of discounted future net cash flows at the beginning and end of each year.

	2003	2002	2001
Standardized measure of discounted future net cash flows at January 1	**$106,671**	$52,377	$22,670
Changes in the year resulting from:			
Sales and transfers of oil and gas produced during the year, net of production costs	**(41,679)**	(15,525)	(11,252)
Net change in sales and transfer prices, net of production costs	**(45,194)**	21,167	(3,791)
Extensions, discoveries and other additions, net of future production and development cost	**46,433**	69,718	14,183

Change in estimated future development costs	**9**	(209)	(30)
Development costs incurred during the period that reduced future development costs	**7,486**	3,251	2,291
Revisions of previous quantity estimates	**(8,106)**	(2,801)	(2,279)
Accretion of discount	**10,667**	5,238	4,075
Net change in income taxes	**30,391**	(25,983)	(8,498)
Purchases of proved reserves in place	**-**	-	40,000
Sales of proved reserves in place	**(18,263)**	(5,810)	(1,710)
Change in production rates (timing) and other	**2,144**	5,248	(3,282)
Standardized measure of discounted future net cash flows at December 31	**$90,559**	$106,671	$52,377