Bonterra

Energy Income Trust

2004 INTERIM REPORT

For the nine months ended September 30, 2004

Highlights

	Three Months Ended September 30 2004	Three Months Ended September 30 2003[2]	Nine Months Ended September 30 2004	Nine Months Ended September 30 2003[2]
FINANCIAL				
Revenue – oil and gas				
(net of royalties)	**$12,790,000**	$ 9,587,000	**$34,800,000**	$28,852,000
Funds Flow from Operations [1]	**$ 7,499,000**	$ 5,319,000	**$20,928,000**	$16,414,000
Per Unit - Basic	**$ 0.52**	$ 0.38	**$ 1.51**	$ 1.21
Per Unit - Diluted	**$ 0.50**	$ 0.38	**$ 1.47**	$ 1.21
Net Earnings	**$ 5,393,000**	$ 3,223,000	**$13,977,000**	$10,514,000
Per Unit - Basic	**$ 0.38**	$ 0.24	**$ 1.01**	$ 0.78
Per Unit - Diluted	**$ 0.36**	$ 0.24	**$ 0.98**	$ 0.78
Cash Distributions per Unit	**$ 0.51**	$ 0.38	**$ 1.33**	$ 1.19
Capital Expenditures	**$ 1,476,000**	$ 1,453,000	**$ 4,905,000**	$ 3,026,000
Total Assets			**$ 80,811,000**	$77,429,000
Debt			**$ 4,995,000**	$21,642,000
Unitholders' Equity			**$56,380,000**	$38,355,000
OPERATIONS				
Oil and NGL's - Barrels Per Day	**2,339**	2,325	**2,363**	2,369
Natural Gas - MCF Per Day	**5,214**	4,386	**4,834**	4,447

(1) Funds flow from operations is not a recognized measure under GAAP. Management believes that in addition to net earnings, funds flow from operations is a useful supplemental measure as it demonstrates the Trust's ability to generate the cash necessary to make trust distributions, repay debt or fund future growth through capital investment. Investors are cautioned, however, that this measure should not be construed as an indication of the Trust's performance. The Trust's method of calculating this measure may differ from other issuers and accordingly, it may not be comparable to that used by other issuers. For these purposes, the Trust defines funds flow from operations as funds provided by operations before changes in non-cash operating working capital items.

(2) Figures have been restated to conform to current accounting policies. See notes to financial statements.

Report to Unitholders

Bonterra Energy Income Trust (the Trust) is pleased to report its results for the first nine months of 2004. The Trust has been successful in generating substantial increases in net revenue, funds flow and net earnings on a gross and per unit basis. Cash distributions based on operations for the first nine months of 2004 were $1.33 per unit ($18,874,000 or 90 percent of funds flow) compared to $1.19 per unit ($15,908,000 or 97 percent of funds flow) for the first nine months of 2003.

Offer to Purchase Novitas Energy Ltd.

On October 27, 2004, the Trust and Novitas Energy Ltd. (Novitas) jointly announced that they have entered into an agreement for the Trust to acquire Novitas for $0.88 per Novitas common share, plus the assumption of approximately $4.3 million of debt (net of working capital), for total consideration of approximately $37.7 million. Shareholders of Novitas may elect to receive the purchase price of $0.88 for each share of Novitas on the basis of 0.03636 of a Trust Unit (being a ratio of 27.5 Novitas shares for each Trust Unit) or a combination of $0.176 in cash and 0.0291 of a Trust Unit. It is expected that the transaction will close in early January, 2005.

This transaction will benefit the Trust by creating a larger production, reserve, and undeveloped land base; by creating a larger financial capacity and market capitalization; by having access to two new areas of production and exploitation in order to broaden its production and reserve base; and by creating economies of scale in operations and administration. For further details with regard to this transaction please refer to www.sedar.com or www.bonterraenergy.com.

A Discussion of Financial and Operational Results

The following report dated November 1, 2004 is a review of the operations, current financial position and outlook for the Trust and should be read in conjunction with the unaudited financial statements for the nine months ended September 30, 2004, including the notes related thereto, and the audited financial statements for the fiscal year ended December 31, 2003, together with the notes related thereto.

Average daily production volume for the nine months ended September 30, 2004 was 3,169 barrels of oil equivalent (BOE's) per day. BOE's are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation. Production consists of 2,363 barrels per day of crude oil and natural gas liquids and 4,834 MCF per day of natural gas. Bonterra's comparable 2003 period production average was 3,110 BOE's per day consisting of 2,369 barrels per day of crude oil and natural gas liquids and 4,447 MCF per day of natural gas. The Trust continues to experience success in its shallow gas and CBM development.

Net revenue from petroleum and natural gas sales was $34,800,000 in the first nine months of 2004 compared to $28,852,000 for the nine months ended September 30, 2003. The increase in net revenue over the corresponding 2003 period was due primarily to higher net commodity prices. The average Canadian price received net of hedging adjustments for crude oil and natural gas liquids during the first nine months of 2004 was $45.78 per barrel and $6.80 per MCF for natural gas compared to $40.13 per barrel and $5.39 per MCF in the corresponding 2003 period. The increase of $1,567,000 of net revenue in the third quarter over the second quarter of 2004 was also primarily driven by higher commodity prices.

Substantial increases in the price of U.S. WTI oil prices and U.S. Nymex natural gas pricing were substantially offset by the rising Canadian dollar. The negative impact on the first nine months of 2004 compared to the first nine months of 2003 to the Trust's funds flow from operations of the rising Canadian dollar was approximately 34 cents per unit and approximately 31 cents per unit on net earnings.

The Trust incurred a $1,861,000 (2003 - $3,056,000) hedging loss during the first nine months of 2004. The Trust currently has fixed price contracts for approximately 20 percent of its estimated future 12 month oil production and has costless collars for about 20 percent of its next 12 months natural gas production which guarantees a floor price and a maximum high price. Please see note eight to the financial statements for a current listing of the Trust's outstanding hedging agreements.

Production costs for the nine months ended September 30, 2004 were $12,072,000 compared to $10,828,000 for the nine months ended September 30, 2003. On a BOE basis production costs averaged $13.90 in 2004 verses $12.74 in the corresponding 2003 period. Increased costs associated with the Trust's Dodsland operations ($26.70 per BOE in 2004 compared to $22.20 in the corresponding 2003 nine month period) and inflationary increases in maintenance costs were the primary reason for the production cost increase.

The Trust currently operates its Dodsland production through third party operating agreements which allow the Trust to transfer all uneconomic wells to the respective operator at no cost and the responsibility for the abandonment and reclamation costs are transferred to the third party. In the latter part of the second quarter and third quarter a significant amount of costs (approximately $400,000) were incurred to enhance production from this area through maintenance of several low production wells. Average production for the first nine months of 2004 from the Trust's Dodsland production was 422 BOE per day.

The Trust's production comes primarily from low productivity wells. These wells generally result in higher production costs on a per unit-of-production basis as costs such as municipal taxes, surface lease, power and personnel costs are not variable with production volumes. As the Trust develops its shallow natural gas potential, the average costs per BOE should decline. The high production costs for the Trust are substantially offset by low royalty rates of approximately 10 percent, which is much lower than industry average for conventional production and results in high cash net backs on a combined basis despite higher than average production costs.

General and administrative expenses were $1,267,000 in the first nine months of 2004 compared to $1,105,000 in the nine months ended September 30, 2003. Costs on a BOE basis increased to $1.46 per BOE in the first nine months of 2004 compared to $1.30 per BOE in the first half of 2003. In addition, third quarter 2004 general and administrative expenses were $189,000 greater than during the second quarter of 2004. During the latter part of the second quarter and third quarter the Trust along with its legal and financial advisors examined its continuous disclosure documents to enable the Trust to qualify as a POP issuer. This was done to facilitate the June 30 financing as well as for future possible acquisition deals including the anticipated Novitas Energy Ltd. (Novitas) acquisition. Salary compensation also increased by approximately $200,000 due to additional staff and general compensation increases.

Interest expense decreased to $446,000 for the nine months ended September 30, 2004 compared to $669,000 for the nine months ended September 30, 2003. The Trust's public offering that closed on June 30, 2004 raised $20,275,000 net of unit issue costs. These proceeds were used to reduce the outstanding debt of the Trust in anticipation of exploiting its shallow gas and CBM potential. The Trust anticipates a significant development program being undertaken in 2005.

Provision for depletion, depreciation and accretion was $6,066,000 and $5,618,000 for the nine month periods ending September 30, 2004 and September 30, 2003 respectively. The increase was primarily due to depletion resulting from the additional drilling done by the Trust during 2003 and 2004. The 2004 change in accounting policy, related to accounting for the Trust's asset retirement obligation (formerly future site restoration), did not result in a significant change in the Trust's provision for depletion, depreciation and accretion.

The Trust is providing for $375,000 in current taxes. The current taxes are the result of earnings in the Trust's corporate subsidiaries that can not be sheltered by the subsidiaries' corporate tax pools. Due to high commodity prices increasing corporate cash flow and poor weather conditions causing capital expenditure delays, the Trust's subsidiaries are generating taxable income. With the commencement of the Trust's shallow gas, CBM and Cardium oil infill programs additional capital expenditures will be incurred over the balance of 2004 and 2005 which should result in the recovery of any current taxes.

Funds flow from operations increased by $4,514,000 from $16,414,000 in the first nine months of 2003 to $20,928,000 in the first nine months of 2004. The increase in 2004 was due to higher net commodity prices after adjusting for hedging losses partially offset by higher production costs. The following reconciliation compares funds flow to the Trust's net earnings as calculated according to Canadian generally accepted accounting principles:

For the periods ended September 30	**Three Months**		**Nine Months**	
	2004	**2003**	**2004**	**2003**
Net earnings for the period	**$5,393,000**	$3,223,000	**$ 13,977,000**	$10,514,000
Unit option expense	**71,000**	70,000	**195,000**	180,000
Depletion, depreciation and accretion	**2,061,000**	1,909,000	**6,066,000**	5,618,000
Future income taxes	**(26,000)**	117,000	**690,000**	102,000
Funds flow from operations	**$7,499,000**	$5,319,000	**$20,928,000**	$16,414,000

Net earnings for the first nine months of 2004 were $13,977,000 compared to $10,514,000 in the corresponding 2003 period. The increase was primarily due to increased commodity prices offset partially by higher production costs and increased tax provision.

Two new expenses were required to be reported in 2004 due to regulatory changes. Due to the change in accounting policy regarding the reporting of stock-based compensation plans, the Trust reported a $195,000 expense (2003 restated amount of $180,000). The Trust also reported an accretion expense of $419,000 (2003 restated amount of $413,000), that has been included in depletion, depreciation and accretion expense, relating to the discounting of its asset retirement obligation. The accretion expense represents the discount rate used to calculate the Trust's asset retirement obligation. The rate the Trust uses in the calculation is a credit-adjusted risk-free interest rate of 5 percent. This rate is reviewed annually and if changed may have a substantial impact on the present value of the asset retirement obligation.

During the first quarter of 2004, the Trust provided a temporary operating loan to Novitas, a company with common directors and management. The loan has an interest rate of bank prime plus one-half percent. There is no security provided for the loan, however, the management agreement in place between Novitas and the Trust, originally established as a 90 day automatic renewal, can not be terminated as long as the loan remains outstanding. Interest paid on the loan during the first nine months of 2004 was $34,000.

During the nine months ended September 30, 2004 the Trust received a management fee from Novitas for management services of $220,000 (2003 - $128,000). Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties during the first nine months of 2004 of $142,000 (2003 - $134,000).

Comaplex Minerals Corp. (Comaplex) a company with common directors and management paid a management fee to the Trust for management services of $180,000 (2003 - $135,000). At December 31, 2003 the Trust owed Comaplex $3,750,000 which was repaid prior to the end of the second quarter 2004.

The above charges all represent the fair value of the services rendered. The Trust records these receipts of management fees as a reduction in general and administrative expenses.

The Trust is authorized to issue an unlimited number of trust units without nominal or par value. The following table outlines changes in the Trust's unit structure during the nine month periods ended September 30:

	2004		2003	
Issued	Number	Amount	Number	Amount
Trust Units				
Balance, beginning of period	13,521,405	$51,764,000	13,368,405	$50,199,000
Issued pursuant to Trust unit option plan	115,500	1,151,000	-	-
Issued pursuant to public offering	1,100,000	21,450,000	-	-
Unit issue costs for public offering	-	(1,175,000)	-	-
Transfer of contributed surplus to unit capital	-	63,000	-	-
Balance, end of period	14,736,905	$73,253,000	13,368,405	$50,199,000

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,323,450 (2003 - 1,323,450) trust units. The exercise price of each option granted equals the market price of the trust unit on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Trust's unit option plan as of September 30, 2004 and 2003, and changes during the nine month periods ending on those dates is presented below:

	2004 Options	2004 Weighted-Average Exercise Price	2003 Options	2003 Weighted-Average Exercise Price
Outstanding at beginning of period	937,000	$10.96	963,000	$10.00
Options granted	10,000	15.60	36,000	9.70
Options exercised	(115,500)	10.00	-	-
Options cancelled	(60,000)	10.00	(84,000)	10.00
Outstanding at end of period	771,500	$11.24	915,000	$ 9.99
Options exercisable at end of period	64,500	$10.00	-	$ -

The following table summarizes information about fixed unit options outstanding at September 30, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 09/30/04	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 09/30/04	Weighted-Average Exercise Price
$9.70-$10.00	586,500	2.4 years	$ 9.99	64,500	$10.00
$15.20-$15.60	185,000	2.8 years	15.22	-	-
$9.70-$15.60	771,500	2.5 years	$11.24	64,500	$10.00

During the first nine months of 2004, the Trust incurred capital costs of $4,905,000 (excluding costs of abandonment) consisting primarily of $3,389,000 for drilling, completing and tying in of 16 (net 14.2) natural gas wells, $713,000 for drilling of non-operated infill oil wells, and $513,000 for tying in and increasing the deliverability of natural gas wells drilled in 2003. Of the natural gas wells drilled by the Trust, four (3.25 net) are awaiting tie-in.

As previously mentioned, the Trust has entered into an Offer to Purchase all of the outstanding common shares of Novitas for $0.88 per share on the basis of, at the election of the shareholders of Novitas, 0.03636 of a Trust unit (being a ratio of 27.5 common shares to one Trust unit) for each common share of Novitas or $0.176 cash and 0.0291 of a Trust unit for each common share of Novitas. The Offer to Purchase is open to January 6, 2005. The offer is subject to several conditions including the tendering of at least 90 percent (on a fully diluted basis) of the outstanding common shares of Novitas.

If all Trust units were issued as per option one, 1,381,361 Trust units would be issued and the Trust would assume approximately $4,550,000 of debt. Should all shareholders of Novitas exercise option two above, the acquisition would result in additional debt to the Trust of approximately $10,800,000 (including Novitas debt of $4,550,000) and the issue of approximately 1,105,545 Trust units.

Should the acquisition of Novitas close, the Trust's 2005 production is anticipated to increase by 700 BOE's per day with corresponding increases in oil and gas sales, royalty expenses, production costs, interest expense and depletion expenses. The impact to general and administration expenses is expected to be nominal.

The Trust currently has plans to drill or recomplete a further seven (approximately six net) shallow gas (including CBM) wells in 2004. In addition, seven (approximately 6.5 net) oil wells are anticipated to be drilled by the Trust prior to the end of 2004. Drilling success in 2004 and 2005 should substantially increase production and reserves. Further infill drilling in 2004 to enhance crude oil production is planned in several areas where the Trust has non-operated interests. The Trust will participate with the operator of the properties on these prospects.

Additional information relating to the Trust may be found on SEDAR.COM.

For further information please visit our website at www.bonterraenergy.com.

Submitted on behalf of the Board of Directors,

George F. Fink
President, CEO and Director

Management's Responsibility for Financial Statements

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of these statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Trust's assets are safeguarded and to facilitate the preparation of relevant and timely information.

The Trust's auditors have not performed a review of these interim financial statements. The audit committee has reviewed these financial statements with management and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this interim report.

Consolidated Statements of Operations and Accumulated Earnings

For the periods ended Sept. 30 (unaudited)

	Three Months 2004	Three Months 2003 (Restated see Note 1)	Nine Months 2004	Nine Months 2003 Restated see Note 1)
Revenue				
Oil and gas sales,				
net of royalties	**$12,790,000**	$9,587,000	**$34,800,000**	$28,852,000
Production costs	**(4,455,000**)	(3,737,000)	**(12,072,000)**	(10,828,000)
Alberta royalty tax credits	**80,000**	53,000	**197,000**	174,000
Interest and other	**12,000**	4,000	**91,000**	12,000
	8,427,000	5,907,000	**23,016,000**	18,210,000
Expenses				
General and administrative	**515,000**	358,000	**1,267,000**	1,105,000
Interest on debt	**39,000**	224,000	**446,000**	669,000
Unit option expense (Note 1)	**71,000**	70,000	**195,000**	180,000
Depletion, depreciation and				
accretion (Note 1)	**2,061,000**	1,909,000	**6,066,000**	5,618,000
	2,686,000	2,561,000	**7,974,000**	7,572,000
Earnings before Income Taxes	**5,741,000**	3,346,000	**15,042,000**	10,638,000
Income Taxes (Recovery)				
Current	**374,000**	6,000	**375,000**	22,000
Future	**(26,000)**	117,000	**690,000**	102,000
	348,000	123,000	**1,065,000**	124,000
Net Earnings for the Period	**5,393,000**	3,223,000	**13,977,000**	10,514,000
Accumulated earnings at				
beginning of period	**39,903,000**	24,668,000	**31,319,000**	17,377,000
Accumulated Earnings at				
End of Period	**$45,296,000**	$27,891,000	**$45,296,000**	$27,891,000
Net Earnings per Trust Unit				
– Basic	**$0.38**	$0.24	**$1.01**	$0.78
Net Earnings per Trust Unit				
– Diluted	**$0.36**	$0.24	**$0.98**	$0.78

Consolidated Statements of Cash Flows

For the periods ended Sept. 30 (unaudited)

	Three Months 2004	Three Months 2003 (Restated see Note 1)	Nine Months 2004	Nine Months 2003 Restated see Note 1)
Operating Activities				
Net earnings for the period	**$5,393,000**	$3,223,000	**$13,977,000**	$10,514,000
Items not affecting cash				
Unit option expense (Note 1)	**71,000**	70,000	**195,000**	180,000
Depletion, depreciation and accretion (Note 1)	**2,061,000**	1,909,000	**6,066,000**	5,618,000
Future income taxes	**(26,000)**	117,000	**690,000**	102,000
	7,499,000	5,319,000	**20,928,000**	16,414,000
Change in non-cash operating working capital items				
Accounts receivable	**(382,000)**	167,000	**(1,785,000)**	743,000
Crude oil inventory	**57,000**	75,000	**95,000**	10,000
Parts inventory	**13,000**	(43,000)	**(13,000)**	(55,000)
Prepaid expenses	**200,000**	(151,000)	**(281,000)**	(452,000)
Accounts payable and accrued liabilities	**379,000**	1,004,000	**1,116,000**	129,000
	267,000	1,052,000	**(868,000)**	375,000
Cash Provided by Operating Activities	**7,766,000**	6,371,000	**20,060,000**	16,789,000
Financing Activities				
Increase (decrease) in debt	**2,214,000**	296,000	**(16,835,000)**	2,012,000
Decrease (increase) in due from related party (Note 2)	**175,000**	-	**(225,000)**	-
Proceeds on issuance of units pursuant to public offering	**-**	-	**21,450,000**	-
Unit issue costs	**3,000**	-	**(1,175,000)**	-
Unit option proceeds	**-**	-	**1,151,000**	-
Unit distributions	**(7,074,000)**	(5,214,000)	**(17,822,000)**	(15,775,000)
Cash Used in Financing Activities	**(4,682,000)**	(4,918,000)	**(13,456,000)**	(13,763,000)
Investing Activities				
Property and equipment expenditures	**(1,570,000)**	(1,453,000)	**(5,090,000)**	(3,026,000)
Abandonment deposit (Note 4)	**(1,514,000)**	-	**(1,514,000)**	-
Cash Used in Investing Activities	**(3,084,000)**	(1,453,000)	**(6,604,000)**	(3,026,000)
Net Cash Inflow	**-**	-	**-**	-
Cash, beginning of period	**-**	-	**-**	-
Cash, End of period	**$-**	$-	**$-**	$-
Cash Interest Paid	**$39,000**	$224,000	**$446,000**	$669,000
Cash Taxes Paid	**$-**	$6,000	**$1,000**	$22,000

Consolidated Balance Sheets
As at September 30, 2004 (unaudited)
and December 31, 2003

	2004	2003 (Restated see Note 1)
Assets		
Current		
Accounts receivable	**$6,290,000**	$4,505,000
Crude oil inventory (Note 1)	**567,000**	662,000
Parts inventory	**373,000**	360,000
Due from related party (Note 2)	**225,000**	-
Prepaid expenses	**997,000**	716,000
Investments in related party (Note 3)	**461,000**	461,000
Total Current Assets	**8,913,000**	6,704,000
Abandonment Deposit (Note 4)	**1,514,000**	-
Property and Equipment (Note 5)		
Petroleum and natural gas properties and related equipment	**97,498,000**	92,636,000
Accumulated depletion and depreciation	**(27,114,000)**	(21,504,000)
Net Property and Equipment	**70,384,000**	71,132,000
	$80,811,000	$77,836,000
Liabilities		
Current		
Distributions payable	**$-**	$1,623,000
Accounts payable and accrued liabilities	**6,919,000**	5,803,000
Debt (Note 6)	**4,995,000**	21,830,000
Total Current Liabilities	**11,914,000**	29,256,000
Future Income Tax Liability	**1,075,000**	385,000
Asset Retirement Obligations (Note 1)	**11,442,000**	11,214,000
Total Liabilities	**24,431,000**	40,855,000
Unitholders' Equity		
Unit capital (Note 7)	**73,253,000**	51,764,000
Contributed surplus	**363,000**	231,000
Accumulated earnings	**45,296,000**	31,319,000
Accumulated cash distributions	**(62,532,000)**	(46,333,000)
Total Unitholders' Equity	**56,380,000**	36,981,000
	$80,811,000	$77,836,000

Consolidated Statements of Unitholders' Equity

For the periods ended Sept. 30 (unaudited)

	Three Months 2004	Three Months 2003 (Restated see Note 1)	Nine Months 2004	Nine Months 2003 Restated see Note 1)
Unitholders' equity, beginning of period	**$57,987,000**	$40,276,000	**$36,981,000**	$42,075,000
Net earnings for the period	**5,393,000**	3,223,000	**13,977,000**	10,514,000
Net capital contributions (Note 7)	**3,000**	-	**21,426,000**	-
Unit option adjustment	**71,000**	-	**195,000**	-
Cash distributions	**(7,074,000)**	(5,214,000)	**(16,199,000)**	(14,304,000)
Unitholders' Equity, End of Period	**$56,380,000**	$38,285,000	**$56,380,000**	$38,285,000

Notes to the Consolidated Interim Financial Statements

Periods ended September 30, 2004 and 2003 (unaudited)

1. Significant Acccounting Policies

The accounting policies and methods of application followed in the preparation of the interim financial statements are the same as those followed in the preparation of the Trust's 2003 annual financial statements except for the following items. The interim financial statements as presented should be read in conjunction with the 2003 annual financial statements.

- Stock-based compensation plan

  Effective January 1, 2004 the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") section 3870, "Stock-based Compensation and Other Stock-based Payments", retroactively with restatement of prior periods. The recommendations require the Trust to record a compensation expense over the vesting period based on the fair value of options granted to employees and directors.

  The change resulted in the following amendments to figures for the three months and nine months ended September 30, 2003 and balances as at December 31, 2003:

	Three Months 2003 As reported	Three Months 2003 Restated	Nine Months 2003 As reported	Nine Months 2003 Restated
Unit option expense	$ -	$ 70,000	$ -	$ 180,000
Unit capital			51,137,000	51,172,000
Contributed surplus (December 31, 2003)			-	231,000
Accumulated earnings (January 1, 2003)			17,841,000	17,786,000
Accumulated earnings (December 31, 2003)			31,879,000	31,613,000

• Asset retirement obligations

Effective January 1, 2004 the Trust retroactively adopted the CICA section 3110, "Asset Retirement Obligations". The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-life assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is adjusted over time for changes in the value of the liability through accretion charges which are included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

The change resulted in the following amendments to figures for the three months and nine months ended September 30, 2003 and balances as at December 31, 2003:

	Three Months		Nine Months	
	2003 As reported	2003 Restated	2003 As reported	2003 Restated
Depletion, depreciation and accretion	$1,954,000	$1,909,000	$ 5,753,000	$ 5,618,000
Future income tax expense	98,000	117,000	56,000	102,000
Unit capital			51,172,000	51,764,000
Accumulated earnings (January 1, 2003)			17,786,000	17,882,000
Accumulated earnings (December 31, 2003)			31,613,000	31,820,000
Petroleum and natural gas properties and related equipment			87,032,000	92,636,000
Accumulated depletion and depreciation			(19,545,000)	(21,366,000)
Asset retirement obligations			8,573,000	11,214,000
Future income tax liability			41,000	385,000

At September 30, 2004, the estimated total undiscounted amount required to settle the asset retirement obligations was $28,360,000. These obligations will be settled based on the useful lives of the underlying assets, which extend up to 40 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of 5 percent.

Changes to asset retirement obligations were as follows:

	Nine months ended September 30, 2004
Asset retirement obligations, December 31, 2003	$ 11,214,000
Adjustment to opening asset retirement obligation	(7,000)
Liabilities settled during the period	(185,000)
Accretion	420,000
Asset retirement obligations, September 30, 2004	$ 11,442,000

- Crude oil inventory

Effective January 1, 2004 the Trust will record its crude oil inventory at the lower of cost and net realizable value. Inventory cost is determined based on combined average per barrel operating costs, royalties and depletion and depreciation for the period and net realizable value is determined based on sales price in the month preceding period end. The change resulted in the following amendments to figures for the three months and nine months ended September 30, 2003 and balances as at December 31, 2003:

	Three Months		Nine Months	
	2003 As reported	2003 Restated	2003 As reported	2003 Restated
Oil and gas sales, net of royalties	$9,315,000	$9,587,000	$28,669,000	$28,852,000
Production costs	3,670,000	3,737,000	10,820,000	10,828,000
Accumulated earnings (January 1, 2003)			17,882,000	17,377,000
Accumulated earnings (December 31, 2003)			31,820,000	31,319,000
Accounts receivable			5,530,000	4,505,000
Crude oil inventory			-	662,000
Accumulated depletion and depreciation			(21,366,000)	(21,504,000)

- Hedging relationships

The CICA published an amended Accounting Guideline 13, “Hedging Relationships”, effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. All derivative instruments that do not qualify as a hedge under the guideline, or are not properly designated as a hedge, will be recorded on the balance sheet as either an asset or liability with changes in fair value recognized in earnings. The Trust adopted the standard January 1, 2004 with no impact on the financial results.

Derivative financial instruments are utilized to reduce commodity price risk on the Trust's product sales. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified product sale. The Trust believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity. The production volume in the instruments all match the production being hedged.

The commodity price swap agreements are used as part of the Trust's program to manage its product pricing. The commodity price swap agreements involve the periodic exchange of payments and are recorded as adjustments of net revenue. During the nine month period ended September 30, 2004 the Trust recorded a reduction to net revenue of $1,861,000 (Nine months ended September 30, 2003 - $3,056,000)

The cumulative impact of the above described accounting changes to the first nine months of 2003 was an increase in net earnings of $84,000 and an increase of one cent per unit in Basic and Diluted Earnings per Trust Unit.

2. Related Party Transactions

During the first quarter of 2004, the Trust provided a temporary operating loan to Novitas Energy Ltd. (Novitas), a company with common directors and management. The loan has an interest rate of bank prime plus one-half percent. There is no security provided for the loan, however, the management agreement in place between Novitas and the Trust, originally established as a 90 day automatic renewal, can not be terminated as long as the loan remains outstanding. Interest paid on the loan during the first nine months of 2004 was $34,000

During the nine months ended September 30, 2004 the Trust received a management fee from Novitas for management services of $220,000 (2003 - $128,000). Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties. Total amounts paid during the first nine months of 2004 were $142,000 (2003 - $134,000).

Comaplex Minerals Corp. (Comaplex) a company with common directors and management paid a management fee to the Trust for management services of $180,000 (2003 - $135,000).

The above charges all represent the fair value of the services rendered.

3. Investments

Investments consist of 689,682 (December 31, 2003 - 689,682) common shares in Comaplex (See note 2). The investment is recorded at cost with the fair market value based on the trading price of stock at September 30, 2004 of $2,483,000 (December 31, 2003 - $2,931,000). The common shares trade on the Toronto Stock Exchange under the symbol CMF. The investment represents less than a two percent ownership in the outstanding shares of Comaplex. At December 31, 2003 the Trust owed Comaplex $3,750,000 which was repaid prior to September 30, 2004.

4. Abandonment Deposit

The Trust under the Province of Alberta Regulations provided a cash deposit with the Alberta Energy and Utilities Board for the future abandonment of specific wells. The deposit is refundable based on several conditions including abandonment or reactivation of inactive wells. The deposit bears interest at Canadian chartered bank prime less approximately 2 percent.

5. Property and Equipment

	September 30, 2004		December 31, 2003	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Undeveloped land	$ 309,000	$ -	$ 186,000	$ -
Petroleum and natural gas properties and related equipment	96,490,000	26,881,000	91,774,000	21,311,000
Furniture, equipment and other	699,000	233,000	676,000	193,000
	$97,498,000	$27,114,000	$92,636,000	$21,504,000

6. Debt

The Trust has a bank revolving credit facility of $32,000,000 at September 30, 2004 (December 31, 2003 - $32,000,000). The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. The amount available for borrowing under the credit facility is reduced by the amount of outstanding letters of credit. As of September 30, 2004, the Trust has $244,000 (December 31, 2003 - $234,000) of outstanding letters of credit. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Trust's assets, and a general security agreement.

Fourteen million dollars of the credit facility carries an interest rate of Canadian chartered bank prime with the balance at one-quarter percent above prime. As of September 30, 2004, the Trust had an outstanding balance under the facility of $4,995,000 (December 31, 2003 - $17,466,000). The Trust has classified borrowing under its bank facilities as a current liability as required by guidance under the CICA's Emerging Issues Committee Abstract 122. It has been management's experience that these types of loans which are required to be classified as a current liability are seldom called by principal bankers as long as all the terms and conditions of the loan are complied with. Cash interest paid during the nine month period ended September 30, 2004 for this loan was $409,000 (corresponding 2003 period - $476,000).

As at December 31, 2003, the Trust had a balance payable of $3,750,000 to Comaplex (see notes 2 and 3). The loan has been repaid prior to September 30, 2004. The interest rate was bank prime less three-quarters of a percent. The security provided by the Trust for the loan was that the Trust has agreed to maintain a line of credit with its principal banker sufficient to repay the loan if demanded. Cash interest paid during the nine month period ended September 30, 2004 for this loan was $37,000 (corresponding 2003 period - $238,000).

7. Unit Capital

Authorized

The Trust is authorized to issue an unlimited number of trust units without nominal or par value

Issued	Number	Amount
Trust Units		
Balance, January 1, 2004	13,521,405	$51,764,000
Issued pursuant to Trust's unit option plan	115,500	1,151,000
Issued pursuant to public offering	1,100,000	21,450,000
Unit issue costs for public offering	-	(1,175,000)
Transfer of contributed surplus to unit capital	-	63,000
Balance, September 30, 2004	14,736,905	$73,253,000

The Trust sold 1,100,000 units at a price of $19.50 pursuant to a public offering which closed on June 30, 2004. Net proceeds after unit issue costs were $20,275,000.

See Note 1 regarding accounting for unit-based compensation plan.

8. Commitments – Future Sales Agreements

The Trust entered into the following commodity hedging transactions for a portion of its 2004 and 2005 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
October 1, 2004 to December 31, 2004	Crude Oil	500 barrels	WTI	$44.20 per barrel
January 1, 2005 to March 31, 2005	Crude Oil	500 barrels	WTI	$43.08 per barrel
April 1, 2005 to June 30, 2005	Crude Oil	500 barrels	WTI	$48.52 per barrel
July 1, 2005 to September 30, 2005	Crude Oil	500 barrels	WTI	$50.02 per barrel
October 1, 2005 to December 31, 2005	Crude Oil	500 barrels	WTI	$55.60 per barrel
April 1, 2004 to October 31, 2004	Natural Gas	1,500 GJ's	AECO	Floor of $4.75 and ceiling of $7.25 per GJ
April 1, 2004 to October 31, 2004	Natural Gas	2,000 GJ's	AECO	Floor of $5.75 and ceiling of $7.35 per GJ
November 1, 2004 to March 31, 2005	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $9.50 per GJ
November 1, 2004 to March 31, 2005	Natural Gas	1,500 GJ's	AECO	Floor of $5.70 and ceiling of $9.00 per GJ

9. Subsequent Event – Distribution

Subsequent to September 30, 2004, the Trust declared its distribution of $0.18 per unit payable on October 29, 2004 to Unitholders of record on October 15, 2004. The distribution represents earnings in the Trust for the month of September 2004.

10. Subsequent Event – Acquisition

The Trust has entered into an agreement to acquire Novitas for $0.88 per common share, plus the assumption of approximately $4.3 million of debt (net of working capital) for total consideration of approximately $37.7 million. The shareholders of Novitas may elect to receive the purchase price of $0.88 for each share of Novitas on the basis of 0.03636 of a trust unit of the Trust (being a ratio of 27.5 Novitas shares for each Trust unit) or a combination of $0.176 in cash and 0.0291 of a trust unit of the Trust. The takeover is subject to numerous terms and conditions including the tendering of at least 90 percent of the outstanding shares of Novitas and is scheduled to close in the first week of January 2005. Funding for the cash portion of the acquisition will come from the Trust's available bank lines.

The acquisition, should it be completed, will be accounted for at carrying value due to the related status of Novitas to the Trust.

Bonterra
Energy Income Trust

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