Bonterra Energy Income Trust

Q1

2007 INTERIM REPORT

For the Period Ended March 31, 2007

Highlights

For the Three Months Ended	**March 31 2007**	December 31 2006	March 31 2006
Financial ($000, except $ per share)			
Revenue – oil and gas	**22,602**	21,719	20,131
Funds Flow from Operations (1)	**13,129**	12,235	12,153
Per Unit – Basic	**0.78**	0.72	0.73
Per Unit – Diluted	**0.78**	0.72	0.72
Net Earnings	**8,904**	6,471	9,721
Per Unit – Basic	**0.53**	0.39	0.58
Per Unit – Diluted	**0.53**	0.38	0.58
Cash Distributions per Unit	**0.66**	0.72	0.69
Capital Expenditures	**7,625**	9,457	10,048
Total Assets	**140,926**	134,942	118,439
Working Capital Deficiency (2)	**49,288**	50,187	25,532
Unitholders' Equity	**57,646**	53,359	61,365
Operations			
Oil and NGL's			
Barrels per Day	**3,227**	3,138	2,996
Average Price ($ per barrel)	**62.53**	60.79	57.02
Natural Gas			
MCF per Day	**6,470**	5,885	6,071
Average Price ($ per MCF)	**7.52**	7.57	8.52
Total barrels per day (3)	**4,305**	4,119	4,008

(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 excluding gain on sale of property and asset retirement expenditures.

(2) Includes 100 percent of debt.

(3) 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following report dated May 2, 2007 is a review of the operations and current financial position for Bonterra Energy Income Trust ("Bonterra" or "the Trust") and should be read in conjunction with the unaudited financial statements for the three months ended March 31, 2007, including the notes related thereto, and the audited financial statements for the fiscal year ended December 31, 2006, together with the notes related thereto.

Forward-looking Information

Certain statements contained in this MD&A include statements which contain words such as "anticipate," "could," "should," "expect," "seek," "may," "intend," "likely," "will," "believe" and similar expressions, relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; cash distributions; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas trusts to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do, what benefits will be derived therefrom. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

General

Bonterra has been successful on a year over year quarterly basis in increasing production volumes, revenue, and funds flow on a gross and per unit basis. Earnings declined slightly ($9.7 million Q1 2006; $8.9 million Q1 2007) on a gross and per unit basis due mainly to higher costs, loss of Alberta Royalty Tax Credit, an increase in interest expense, dry hole costs and an increase in depletion, depreciation, and accretion, offset partially by an increase in revenue.

At March 31, 2007, Bonterra had 6 gross (3.8 net) Cardium oil wells, 12 gross (9 net) natural gas wells, and 7 gross (5.5 net) coal-bed methane wells (CBM) drilled but not on production. The majority of these wells (excluding the CBM wells) will be completed and tied-in by the end of Q3 2007. Subject to service costs and government regulations, a few of the CBM wells will also be completed.

While service costs continue to be high, Bonterra will continue to focus more on directing capital expenditures towards completions, tie-ins, reworking of existing wells, recompletion of gas zones to take advantage of new commingling regulations for gas wells, and refracing of existing Cardium oil wells rather than just drilling new wells. Despite reducing the capital expenditure budget for 2007 to $20 million from $38 million in 2006, Bonterra may still grow its production volumes by conducting these types of programs.

With regard to dealing with the possibility of the proposed federal taxation changes being legislated, Bonterra is still taking a wait and see approach. It will deal with this issue when details about the changes are legislated and there is certainty rather than speculation.

The Trust continues to have upside potential by continuing to drill and develop its large inventory of undrilled locations and potentially from additional recovery of oil in place by water flooding, CO_2 sequestration, and by reworking and refracing existing producing and suspended wells.

Quarterly Comparisons

	2007	2006			
	1st	4th	3rd	2nd	1st
Financial ($000, except $ per unit)					
Revenue – oil and gas	**22,602**	21,719	23,665	23,219	20,131
Funds Flow from Operations (1)	**13,129**	12,235	14,401	14,008	12,153
Per Unit – Basic	**0.78**	0.72	0.86	0.84	0.73
Per Unit – Fully Diluted	**0.78**	0.72	0.85	0.83	0.72
Net Earnings	**8,904**	6,471	10,441	10,617	9,721
Per Unit – Basic	**0.53**	0.39	0.62	0.64	0.58
Per Unit – Fully Diluted	**0.53**	0.38	0.62	0.63	0.58
Cash Distributions	**0.66**	0.72	0.72	0.69	0.69
Capital Expenditures and Acquisitions	**7,625**	9,457	12,597	6,246	10,048
Total Assets	**140,926**	134,942	130,655	122,166	118,439
Working Capital Deficiency	**49,288**	50,187	38,853	28,820	25,532
Unitholders' Equity	**57,646**	53,359	60,387	61,202	61,365
Operations					
Oil and Liquids (barrels per day)	**3,227**	3,138	3,024	3,001	2,996
Natural Gas (MCF per day)	**6,470**	5,885	5,925	6,181	6,071

	2005			
	4th	3rd	2nd	1st
Financial ($000, except $ per unit)				
Revenue – oil and gas	21,753	20,532	17,114	16,438
Funds Flow from Operations (1)	12,489	12,209	10,167	9,714
Per Unit – Basic	0.76	0.75	0.62	0.59
Per Unit – Fully Diluted	0.76	0.74	0.61	0.58
Net Earnings	9,918	9,309	7,115	7,126
Per Unit – Basic	0.59	0.57	0.44	0.44
Per Unit – Fully Diluted	0.59	0.56	0.43	0.43
Cash Distributions	0.68	0.60	0.55	0.54
Capital Expenditures and Acquisitions	10,760	3,022	678	42,243
Total Assets	110,149	101,008	99,914	102,088
Working Capital Deficiency	21,972	10,920	11,379	11,896
Unitholders' Equity	57,322	60,662	60,467	61,985
Operations				
Oil and Liquids (barrels per day)	2,814	2,680	2,635	2,724
Natural Gas (MCF per day)	5,795	5,692	5,462	5,649

(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 excluding gain on sale of property and asset retirement expenditures.

Production

Average daily production volume for the three months ended March 31, 2007 was 4,305 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 3,227 barrels per day of crude oil and natural gas liquids and 6,470 MCF per day of natural gas. Bonterra's first quarter 2006 average production was 4,008 BOE's per day consisting of 2,996 barrels per day of crude oil and natural gas liquids and 6,071 MCF per day of natural gas.

The Trust drilled 4 gross (3.4 net) Cardium oil wells and 2 gross (.7 net) shallow gas wells in the first quarter of 2007 on its operated lands. As at March 31, 2007 Bonterra had 6 gross (3.8 net) Cardium oil wells and 12 gross (9 net) natural gas wells and 7 gross (5.5 net) coal-bed wells drilled but not on production. During the first quarter of 2007, the Trust tied-in 10 gross (9.7 net) Cardium wells and 2 gross (1 net) natural gas wells

Management anticipates that the majority of the currently drilled but not producing wells (excluding the coal-bed wells) will be completed and tied-in by the end of the third quarter 2007. It continues to be difficult obtaining services and materials to complete and tie-in wells on a timely basis. In addition, the current spring breakup is preventing completion of the existing inventory of uncompleted wells.

Revenue

Revenue from petroleum and natural gas sales (including hedge gains and losses) for the quarter was $22,602,000 (2006 - $20,131,000). The increase in revenue over the 2006 first quarter was primarily due to higher production from the wells drilled during the 2006 drill program but not completed until late 2006 or early 2007. The average price received for crude oil and natural gas liquids during the first quarter of 2007 was $62.53 per barrel and $7.52 per MCF for natural gas compared to $57.02 per barrel and $8.52 per MCF in the corresponding 2006 period. On a quarter over quarter basis, revenue increased by $883,000 due to increased production volumes and a moderate increase in crude oil prices.

Gross revenue has been increased by $590,000 (2006 decreased $915,000) due to higher prices received as a result of price hedging. The Trust will continue to assess hedging future production to assist in managing its funds flow. The Trust continues to follow the policy of protecting high cost production with hedges that provide a significant level of profitability and also to provide for a reasonable amount of funds flow protection for development projects. The Trust will however maintain a policy of not hedging more than 50 percent of production to allow it to benefit from any price movements in either crude oil or natural gas. Kindly refer to Note 8 to the attached interim financial statements for details. As at March 31, 2007, the fair value of the outstanding commodity hedging contracts was a net liability of $604,000 (December 31, 2006 – net asset of $1,189,000).

Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During the first quarter of 2007 the Trust paid $2,156,000 (2006 - $2,085,000) in Crown royalties and $422,000 (2006 - $494,000) in freehold royalties, gross overriding royalties and net carried interests. The majority of the Trust's wells are low productivity wells and therefore have low Crown royalty rates. The Trust's average Crown royalty rate is approximately ten percent (2006 – ten percent) and approximately 2 percent (2006 – 2.5 percent) for other royalties before hedging adjustments. The Trust was eligible for Alberta Crown Royalty rebates for Alberta production from all wells that it drilled on Crown lands and from a small amount of purchased wells, however this program was discontinued effective January 1, 2007.

Gain on Sale of Property

During the first quarter of 2006, the Trust disposed of a non-operated; non-core property for gross proceeds of $750,000 (approximately $75,000 per producing BOE). The Trust follows successful efforts accounting for its oil and gas properties and therefore reported a gain of $532,000 on the difference between the depleted value of the property and the above proceeds.

Production Costs

Production costs for the three months ended March 31, 2007 were $5,581,000 compared to $5,152,000 for the three months ended March 31, 2006. On a BOE basis production costs averaged $14.40 in 2007 verses $14.28 in the corresponding 2006 period. Operating costs on the Trust's newly drilled wells are in the range of $2 to $7 per BOE due to higher original production volumes. The lower costs per BOE on the new wells are offsetting the escalating costs being charged by service companies.

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. Production costs in the $14 to $15 per BOE range are expected. The high production costs for the Trust are substantially offset by low royalty rates of approximately 12 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

General and administrative expenses were $564,000 in the first quarter of 2007 compared to $632,000 in the three months ended March 31, 2006 and $481,000 in the three months ended December 31, 2006.

Costs on a BOE bases decreased to $1.46 per BOE in the first quarter of 2007 from $1.75 per BOE in the first quarter of 2006. The decrease in general and administrative expenses year over year was due to increased administration fee recoveries on operated production. The quarter over quarter increase was due primarily to increased employee compensation expense and increased annual report, TSX Fees and security commission filing costs associated with filing of the annual report and other continuous disclosure documentation during the first quarter.

Interest Expense

Interest expense increased to $697,000 for the three months ended March 31, 2007 compared to $231,000 for the three months ended March 31, 2006 and $542,000 for the fourth quarter of 2006. Increased average debt levels and increased interest rates were the primary factors in the increase in interest expense. The Trust's net debt as a percentage of annualized first quarter funds flow was approximately eleven and a half months.

The Trust's bank loan of $52,835,000 increased by approximately $7.5 million from the $45,379,000 at December 31, 2006. The increase is due to the payment of the balance of the costs for the 2006 fourth quarter drilling program as well as for expenditures related to the Trusts winter 2007 drill program of $7,625,000 which represents 38 percent of the Trust's estimated 2007 capital expenditure program of $20,000,000.

Unit Based Compensation

Unit based compensation is a statistically calculated value representing the estimated expense of issuing employee unit options. The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. Only 24,000 employee unit options were granted during the first quarter of 2007 resulting in no significant impact to unit based compensation.

Depletion, Depreciation, Accretion and Dry Hole Costs

The Trust follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. For intangible capital costs that result in the addition of reserves, the Trust depletes its oil and natural gas intangible assets using the unit-of-production basis by field. The Trust believes that the successful efforts method of accounting provides a more accurate cost of the producing properties than the alternative measure of full cost accounting.

Provision for depletion, depreciation and accretion was $3,502,000 and $2,597,000 for the three month periods ending March 31, 2007 and March 31, 2006 respectively. The increase was primarily due to increased production resulting from the Trust's 2006 drill program. The Trust continues to replace production declines with newly drilled wells that have higher capital costs. The Trust has capital costs of approximately $6 per proven BOE of reserves based on the December 31, 2006 independent engineering report.

Dry hole costs of $467,000 relate to additional costs required in 2007 to properly reclaim well sites relating to the seven shallow gas wells considered to be dry holes in 2006. No additional dry holes were determined to exist during the first quarter of 2007.

Income Taxes

Taxable income earned within the Trust is required to be allocated to its Unitholders and as such the Trust will not incur any current taxes. However, the Trust operates its oil and gas interests through its 100 percent owned subsidiaries Bonterra Energy Corp. ("Bonterra Corp.") and Novitas Energy Ltd. ("Novitas") and these corporations may periodically be taxable. The Trust amalgamated Bonterra Corp. with Comstate Resources Ltd. effective January 1, 2007.

These corporations pay the majority of their income to the Trust through interest and royalty payments which are deductible for income tax purposes. The current tax provision relates to resource surcharge payable by the Trusts subsidiaries to the Province of Saskatchewan. The surcharge is calculated as a flat percent of revenues generated from the sale of petroleum products produced in Saskatchewan. The provincial government of Saskatchewan has announced its intention to reduce the current resource surcharge rate of 3.3 percent to 3 percent by July 1, 2008.

Future tax provision relates to the future taxes that exist within Bonterra Corp. and Novitas. The liability on the balance sheet relates to temporary differences existing between Bonterra Corp.'s and Novitas' book value of their assets and their remaining tax pools.

The Trust's subsidiaries have the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	$16,303,000
Canadian oil and gas property expenditures	10	1,212,000
Canadian development expenditures	30	34,933,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward (1)	100	9,035,000
		$61,576,000

(1) Income tax losses carried forward expire in 2014 ($635,000), 2015 ($3,574,000) and 2016 ($4,826,000).

The Trust has the following tax pools, which may be used in reducing future taxable income allocated to its Unitholders:

	Rate of Utilization %	Amount
Canadian oil and gas property expenditures	10	$15,317,000
Finance costs	20	554,000
Eligible capital expenditures	7	165,000
		$16,036,000

The Canadian taxable portion of distributions for the 2007 taxation year is calculated on an annual basis and is reported generally by March 1 of the following year.

As of March 31, 2007 proposed Trust taxation legislation has not been substantially enacted and as such the effects of the legislation has not been incorporated into the first quarter report.

Net Earnings

Net earnings decreased to $8,904,000 in the first quarter of 2007 from $9,721,000 in the corresponding 2006 period. Revenue increases due to increased commodity prices and production were generally offset by increased interest expense and depletion, depreciation, accretion and dry hole costs. The Trust's quarter over quarter net earnings increased $2,433,000 primarily due to decreased dry hole costs in Q1 2007 and an increase in production volumes.

Comprehensive Income

On January 1, 2007 the Trust adopted the new accounting standards regarding the accounting for financial instruments. On adoption the Trust increased its investment in related party by $1,836,000 for the fair value of this investment. On January 1, 2007 the

Trust further recognized a current asset of $1,148,000 for the fair value of its commodity derivative contracts. These adjustments resulted in a further increase in the future income tax liability and accumulated other comprehensive income of $604,000 and $2,380,000 respectively.

Other comprehensive income for the quarter included an increase in the unrealized gain on investment in a related party of $982,000, a loss of $315,000 relating to the amortization of the amount recognized in accumulated other comprehensive income on January 1, 2007 for commodity derivative contracts and a loss of $927,000 was recorded in relation to the fair value adjustment on outstanding commodity derivative contracts. All of the above adjustments are net of applicable income tax effects.

Distributable Cash

For the three months ended March 31	**2007**	2006
Cash Flow from Operating Activities	**$12,765,000**	$11,929,000
Less Adjustment for:		
Productive Capacity Maintenance [1]	**(6,160,000)**	(3,777,000)
Long Term Unfunded Contractual Operational Obligations [2]	**(265,000)**	(151,000)
Financing Restrictions Caused by Debt [3]	**–**	–
Distributable Cash from Operations	**$6,340,000**	$8,001,000
Cash generated from the gain on sale of properties	**–**	532,000
Cash generated from increase in debt	**5,121,000**	2,571,000
Working capital adjustments	**(316,000)**	391,000
Unit Distributions [4]	**$11,145,000**	$11,495,000

(1) Bonterra's primary objective is to grow its reserves from which it expects to increase funds flow to increase distributions for its unitholders. The Trust defines Productive Capacity Maintenance as the maintaining of the Trusts proven plus probable reserves. The Trust follows a policy of internal development as its primary method of planned growth. Bonterra has a significant inventory of undrilled Cardium oil infill drilling locations as well as several shallow gas opportunities on its lands or through farm-in agreements. It is management's view that the calculation of the amount required for Productive Capacity Maintenance is the amount of reserves produced in the relevant time period multiplied by the Trust's finding and development costs for proven plus probable reserves. For this purpose the Trust believes that the use of a three year average rate is reasonable given fluctuations in annual costs due to market conditions.

(2) Long Term Unfunded Contractual Operational Obligations in the case of the Trust includes only its Asset Retirement Obligations. For this purpose the Trust calculates this adjustment as the period accretion charge plus the period depletion charge of the asset retirement obligation fixed asset adjustment less actual asset retirement expenditures incurred in the period.

(3) The Trust has no financing restrictions. Please see discussions under Interest Expense and Liquidity and Capital Resources.

(4) Includes distribution declared in April in respect of March operations.

The payout ratio as calculated using distributable cash from operations is 176 percent in the first three months of 2007 compared to 144 percent in the 2006 corresponding period. On a go forward basis the Trust plans to reduce the payout ratio in respect of distributable cash to a level between 110 to 120 percent to facilitate a debt to funds flow level of approximately one year and to incur no current income tax (excluding Saskatchewan Resource Surcharge). This will be attained through better controlling costs of capital replacement, by examining lower cost methods of reserve replacement as well as increased funds flow from wells currently drilled but not tied in. Capital expenditures that are in excess of those required for Productive Capital Maintenance will be funded through additional unit issuances which include employee unit option exercises.

Funds Flow from Operations

Funds flow from operations for the three months ending March 31, 2007 was $13,129,000 compared to $12,153,000 for the three months ended March 31, 2006 and $12,235,000 for the final three months of 2006. Funds flow from operations is not a recognized measure under GAAP. The Trust 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 excluding gain on sale of property and asset retirement expenditures.

The increase over the first quarter of 2006 was primarily due to higher commodity prices and increased production resulting from the Trust's 2006 drill program. As with all oil and gas producers the Trust's funds flow is highly dependent on commodity prices.

The following reconciliation compares funds flow for the first three months of 2007 and 2006 to the Trust's cash flow from operations as calculated according to Canadian generally accepted accounting principles:

	2007	2006
Cash flow from operating activities	$12,765,000	$11,929,000
Items not affecting funds flow:		
Gain on sale of property	-	532,000
Changes in accounts receivable	(539,000)	(275,000)
Changes in crude oil inventory	14,000	127,000
Changes in parts inventory	(8,000)	(75,000)
Changes in prepaid expenses	(48,000)	125,000
Changes in accounts payable and accrued liabilities	897,000	(293,000)
Asset retirement obligations settled	48,000	83,000
Funds flow for the period	$13,129,000	$12,153,000

Cash Netback

The following table illustrates the Trust's cash netback for the three month periods ended:

$ per Barrel of Oil Equivalent (BOE)	March 31 2007	December 31 2006	March 31 2006
Production volumes (BOE)	387,454	378,916	360,720
Gross production revenue	$58.33	$57.32	$55.80
Royalties	(6.65)	(6.37)	(7.15)
Field operating	(14.40)	(15.83)	(14.28)
Field netback	37.28	35.12	34.37
General and administrative	(1.46)	(1.27)	(1.75)
Interest and taxes	(1.99)	(1.64)	(0.91)
Cash netback	$33.83	$32.21	$31.71

Related Party Transactions

The Trust received a management fee from Comaplex Minerals Corp., a company with common directors and management, of $75,000 (2006 - $75,000) for management services and office administration. In addition the Trust received a management fee from Pine Cliff Energy Ltd., a company with common directors and management, of $54,000 (2006 - $54,000) for management services and office administration. These recoveries have been offset against the Trust's general and administrative expense.

Liquidity and Capital Resources

During the first quarter of 2007, the Trust incurred capital costs of $7,625,000. The Trust drilled 4 gross (3.4 net) Cardium oil wells and 2 gross (0.7 net) shallow gas wells in the first quarter of 2007 on its operated lands.

The Trust currently has plans to drill a total of 20 gross (15 net) Cardium infill oil wells in

2007. Total capital cost of approximately $20,000,000 is budgeted for 2007. The capital expenditures will be funded from funds flow, the Trusts lines of credit and funds from the exercising of employee unit options.

The Trust through its operating subsidiaries has a bank revolving credit facility of $59,900,000 at March 31, 2007 (December 31, 2006 - $49,900,000). The credit facility carries an interest rate of Canadian chartered bank prime.

The Trust is authorized to issue an unlimited number of trust units without nominal or par value. Equity transactions during the past three months are as follows:

Issued	Number	Amount
Trust Units		
Balance, January 1, 2007	16,874,658	$89,488,000
Issued pursuant to Trust's unit option plan	31,000	471,000
Transfer of contributed surplus to unit capital	–	50,000
Balance, March 31, 2007	16,905,658	$90,009,000

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,690,000 (December 31, 2006 – 1,687,000) 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.

A summary of the status of the Trust's unit option plan as of March 31, 2007 and December 31, 2006, and changes during the three month and twelve month periods ending on those dates is presented below:

	March 31, 2007		December 31, 2006	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	721,500	$26.55	646,000	$18.67
Options granted	24,000	24.34	447,000	29.18
Options exercised	(31,000)	15.20	(339,500)	15.20
Options cancelled	(8,000)	26.05	(32,000)	24.70
Outstanding at end of period	706,500	$26.98	721,500	$26.55
Options exercisable at end of period	189,500	$23.35	212,500	$22.62

The following table summarizes information about unit options outstanding at March 31, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 3/31/07	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 3/31/07	Weighted-Average Exercise Price
$22.45-$23.35	247,500	2.0 years	$23.32	189,500	$23.35
$24.20-$25.00	24,000	2.8 years	24.34	–	–
$28.70-$28.75	395,000	1.9 years	28.75	–	–
$32.00-$33.75	40,000	2.7 years	33.55	–	–
$22.45-$33.75	706,500	2.0 years	$26.98	189,500	$23.35

Disclosure Controls and Procedures

Disclosure controls and procedures have been designed to ensure the information required to be disclosed by the Trust is accumulated and communicated to the Trust's Management, as appropriate, to allow timely decisions regarding required disclosures. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by the interim filings that the Trust's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Trust. It should be noted that while the Trust's Chief Executive Officer and Chief Financial Officer believe that the Trust's disclosure controls and procedures provide a reasonable level of assurance that they are effective, the do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

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 Balance Sheets

As at March 31, 2007 (unaudited) and December 31, 2006	**2007**	2006
Assets		
Current		
Accounts receivable	**$ 9,683,000**	$ 10,486,000
Crude oil inventory	**873,000**	843,000
Parts inventory	**106,000**	114,000
Prepaid expenses	**1,038,000**	1,086,000
Investments in related party (Notes 1 and 2)	**3,448,000**	461,000
	15,148,000	12,990,000
Property and Equipment (Note 3)		
Petroleum and natural gas properties and related equipment	**183,360,000**	176,602,000
Accumulated depletion and depreciation	**(57,582,000)**	(54,650,000)
Net Property and Equipment	**125,778,000**	121,952,000
	$ 140,926,000	$ 134,942,000
Liabilities		
Current		
Distribution payable	**$ –**	$ 4,050,000
Accounts payable and accrued liabilities	**10,996,000**	13,748,000
Derivative liability (Note 1)	**605,000**	–
Debt (Note 4)	**52,835,000**	45,379,000
	64,436,000	63,177,000
Future Income Tax Liability	**3,888,000**	3,587,000
Asset Retirement Obligations	**14,956,000**	14,819,000
	83,280,000	81,583,000
Commitments (Note 8)		
Unitholders' Equity (Note 5)		
Unit capital	**90,009,000**	89,488,000
Contributed surplus	**1,284,000**	1,116,000
	91,293,000	90,604,000
Deficit	**(35,767,000)**	(37,245,000)
Accumulated other comprehensive income (Note 6)	**2,120,000**	–
	(33,647,000)	(37,245,000)
	57,646,000	53,359,000
	$ 140,926,000	$ 134,942,000

Consolidated Statements of Unitholders' Equity

For the Three Months Ended March 31 (unaudited)	**2007**	2006
Unitholders' equity, beginning of period	**$ 53,359,000**	$ 57,322,000
Comprehensive income for the period	**8,644,000**	9,721,000
Adjustment of opening accumulated comprehensive income (Note 1)	**2,380,000**	–
Net capital contributions	**471,000**	1,817,000
Unit based compensation adjustment	**218,000**	158,000
Distributions declared	**(7,426,000)**	(7,653,000)
Unitholders' Equity, End of Period	**$ 57,646,000**	$ 61,365,000

Consolidated Statements of Operations and Deficit

For the Three Months Ended March 31 (unaudited)	**2007**	2006
Revenue		
Oil and gas sales	**$ 22,012,000**	$ 21,046,000
Hedging gain (loss)	**590,000**	(915,000)
Royalties	**(2,578,000)**	(2,579,000)
Gain on sale of property	**–**	532,000
Alberta royalty tax credits	**–**	176,000
Interest and other	**21,000**	7,000
	20,045,000	18,267,000
Expenses		
Production costs	**5,581,000**	5,152,000
General and administrative	**564,000**	632,000
Interest on debt	**697,000**	231,000
Unit based compensation	**218,000**	158,000
Dry hole costs	**467,000**	–
Depletion, depreciation and accretion	**3,502,000**	2,597,000
	11,029,000	8,770,000
Earnings Before Income Taxes	**9,016,000**	9,497,000
Income Taxes (Recovery)		
Current	**74,000**	99,000
Future	**38,000**	(323,000)
	112,000	(224,000)
Net Earnings for the Period	**8,904,000**	9,721,000
Deficit at beginning of period	**(37,245,000)**	(27,214,000)
Distributions declared	**(7,426,000)**	(7,653,000)
Deficit at End of Period	**($35,767,000)**	($25,146,000)
Net Earnings Per Unit - Basic and Diluted	**$0.53**	$0.58

Consolidated Statement of Comprehensive Income

For the Three Months Ended March 31 (unaudited)	**2007**
Net Earnings for the Period	**$8,904,000**
Unrealized gains and losses on investments (net of income taxes of $170,000)	**982,000**
Gains and losses on derivatives designated as cash flow hedges (net of income taxes of $381,000)	**(927,000)**
Gains and losses on derivatives designated as cash flow hedges in prior periods transferred to net income in the current period (net of income taxes of $129,000)	**(315,000)**
Changes in gains and losses on derivatives designated as cash flow hedges (net of income taxes of $510,000)	**(1,242,000)**
Other Comprehensive Income	**(260,000)**
Comprehensive Income	**$8,644,000**

Consolidated Statements of Cash Flows

For the Three Months Ended March 31 (unaudited)	**2007**	2006
Operating Activities		
Net earnings for the period	**$ 8,904,000**	$ 9,721,000
Items not affecting cash		
Gain on sale of property	**–**	(532,000)
Unit based compensation	**218,000**	158,000
Dry hole costs	**467,000**	–
Depletion, depreciation and accretion	**3,502,000**	2,597,000
Future income taxes (recovery)	**38,000**	(323,000)
	13,129,000	11,621,000
Change in non-cash working capital		
Accounts receivable	**539,000**	275,000
Crude oil inventory	**(14,000)**	(127,000)
Parts inventory	**8,000**	75,000
Prepaid expenses	**48,000**	(125,000)
Accounts payable and accrued liabilities	**(897,000)**	293,000
Asset retirement obligations settled	**(48,000)**	(83,000)
	(364,000)	308,000
Cash Provided by Operating Activities	**12,765,000**	11,929,000
Financing Activities		
Increase in debt	**7,456,000**	7,040,000
Unit option proceeds	**471,000**	1,817,000
Unit distributions	**(11,476,000)**	(11,291,000)
Cash Used in Financing Activities	**(3,549,000)**	(2,434,000)
Investing Activities		
Property and equipment expenditures	**(7,625,000)**	(10,048,000)
Proceeds on sale of property	**–**	750,000
	(7,625,000)	(9,298,000)
Change in non-cash working capital		
Accounts receivable	**264,000**	(991,000)
Accounts payable and accrued liabilities	**(1,855,000)**	794,000
	(1,591,000)	(197,000)
Cash Used in Investing Activities	**(9,216,000)**	(9,495,000)
Net Cash Inflow	**–**	–
Cash, beginning of period	**–**	–
Cash, End of Period	**$ –**	$ –
Cash Interest Paid	**$ 697,000**	$ 231,000
Cash Taxes Paid	**$ 90,000**	$ 112,000

1. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies and methods of application followed in the preparation of the interim financial statements other than described below are the same as those followed in the preparation of the Trust's 2006 annual financial statements. These interim financial statements do not include all disclosure requirements for annual financial statements. The interim financial statements as presented should be read in conjunction with the 2006 annual financial statements.

Financial instruments – recognition and measurement

On January 1, 2007, the Trust adopted Section 3855 of the Canadian Institute of Chartered Accounts' ("CICA") Handbook, "Financial Instruments – Recognition and Measurement". It exposes the standards for recognizing and measuring financial instruments in the balance sheet and the standards for reporting gains and losses in the financial statements. Financial assets available for sale, assets and liabilities held for trading and derivative financial instruments, part of a hedging relationship or not, have to be measured at fair value.

The Trust has made the following classifications:

- Investment in related party is classified as available-for sale and will thus be marked-to-market through comprehensive income at each period end.
- Accounts receivable are classified as loans and receivables and are recorded at amortized cost using the effective interest method. Gains and losses are recognized in net earnings when the asset is no longer recognized.
- Accounts payable and accrued liabilities and bank debt are classified as other financial liabilities and are recorded at amortized cost using the effective interest method. Gains and losses are recognized in net earnings when the liability is no longer recognized.

The adoption of this Section is done retroactively without restatement of the consolidated financial statements of prior periods. As of January 1, 2007, the impact on the consolidated balance sheet of measuring the investment in related party at marked-to-market was an increase of $1,836,000 to investment in a related party, an increase in future tax liability of $270,000 and an increase in accumulated other comprehensive income of $1,566,000.

The impact on the consolidated balance sheet of measuring hedging derivatives at fair value as at January 1, 2007 was an increase in other assets of $1,148,000, an increase in future tax liability of $334,000 and an increase in accumulated other comprehensive income of $814,000.

The Trust selected January 1, 2003 as its transition date for embedded derivatives. An embedded derivative is a component of a financial instrument or another contract of which the characteristics are similar to a derivative. This had no impact on the consolidated financial statements.

Comprehensive income

On January 1, 2007, the Trust adopted Section 1530 of the CICA Handbook, "Comprehensive Income". It describes reporting and disclosure recommendations with respect to comprehensive income and its components. Comprehensive income is the change in unitholders' equity, which results from transactions and events from sources other than the Trust's unitholders. These transactions and events include unrealized gains and losses from changes in fair value of certain financial instruments.

The adoption of this Section implied that the Trust now presents a consolidated statement of comprehensive income as a part of the consolidated financial statements.

Equity

On January 1, 2007, the Trust adopted Section 3251 of the CICA Handbook "Equity" replacing Section 3250 "Surplus". It describes standards for the presentation of equity and changes in equity for reporting periods as a result of the application of Section 1530 "Comprehensive Income".

Hedges

On January 1, 2007, the Trust adopted Section 3865 of the CICA Handbook "Hedges". The recommendations of this Section expand the guidelines required by Accounting Guideline 13(AcG-13), Hedging Relationships. This section describes when and how hedge accounting can be applied as well as the disclosure requirements. Hedge accounting enables the recording of gains, losses, revenues and expenses from the derivative financial instrument in the same period as those related to the hedge item.

Accounting changes

The Trust also adopted Section 1506, "Accounting Changes," the only impact of which is to provide disclosure of when an entity has not applied a new source of GAAP that has been issued but is not yet effective. This is the case with Section 3862, "Financial Instruments Disclosures" and Section 3863, "Financial Instruments Presentations" which are required to be adopted for fiscal years beginning on or after October 1, 2007. The Trust will adopt these standards on January 1, 2008 and it is expected the only effect on the Trust will be incremental disclosures regarding the significance of financial instruments for the entity's financial position and performance; and the nature, extent and management of risks arising from financial instruments to which the entity is exposed.

2. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2006 – 689,682) common shares in Comaplex Minerals Corp. (Comaplex), a company with common directors and management. The investment is recorded at fair market value. The fair market value as determined by using the trading price of the stock at March 31, 2007 was $3,448,000 and at December 31, 2006 was $2,297,000. 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.

3. PROPERTY AND EQUIPMENT

	March 31, 2007		December 31, 2006	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Undeveloped land	$ 334,000	$ –	$ 334,000	$ –
Petroleum and natural gas properties and related equipment	182,067,000	56,971,000	175,353,000	54,008,000
Furniture, equipment and other	959,000	611,000	915,000	642,000
	$183,360,000	$57,582,000	$176,602,000	$54,650,000

4. DEBT

The Trust through its operating subsidiaries has a bank revolving credit facility of $59,900,000 at March 31, 2007 (December 31, 2006 - $49,900,000). 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. Letters of credit totalling $340,000 were issued at March 31, 2007 (December 31, 2006 - $340,000). Security for the credit facility consists of various fixed and floating demand debentures totalling $79,000,000 over all of the Trust's assets, and a general security agreement with first ranking over all personal and real property.

The credit facility carries an interest rate of Canadian chartered bank prime. The Trust has classified this debt as a current liability as required by generally accepted accounting principles. 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 three month periods ended March 31, 2007 and 2006 for these loans were $697,000 and $231,000 respectively.

5. 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, 2007	16,874,658	$89,488,000
Issued pursuant to Trust's unit option plan	31,000	471,000
Transfer of contributed surplus to unit capital	–	50,000
Balance, March 31, 2007	16,905,658	$90,009,000

The number of trust units used to calculate diluted net earnings per unit for the period ended March 31, 2007 of 16,913,263 (2006 – 16,783,806) included the basic weighted average number of units outstanding of 16,899,000 (2006 – 16,676,699) plus 14,263 (2006 – 107,107) units related to the dilutive effect of unit options.

The deficit balance is composed of the following items:

	March 31, 2007	March 31, 2006
Accumulated earnings	$ 131,310,000	$ 94,877,000
Accumulated cash distributions	(167,077,000)	(120,023,000)
Deficit	$(35,767,000)	$(25,146,000)

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,690,000 (December 31, 2006 – 1,687,000) 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.

A summary of the status of the Trust's unit option plan as of March 31, 2007 and December 31, 2006, and changes during the three month and twelve month periods ending on those dates is presented below:

	March 31, 2007		December 31, 2006	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	721,500	$26.55	646,000	$18.67
Options granted	24,000	24.34	447,000	29.18
Options exercised	(31,000)	15.20	(339,500)	15.20
Options cancelled	(8,000)	26.05	(32,000)	24.70
Outstanding at end of period	706,500	$26.98	721,500	$26.55
Options exercisable at end of period	189,500	$23.35	212,500	$22.62

The following table summarizes information about unit options outstanding at March 31, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 3/31/07	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 3/31/07	Weighted-Average Exercise Price
$22.45-$23.35	247,500	2.0 years	$23.32	189,500	$23.35
$24.20-$25.00	24,000	2.8 years	24.34	–	–
$28.70-$28.75	395,000	1.9 years	28.75	–	–
$32.00-$33.75	40,000	2.7 years	33.55	–	–
$22.45-$33.75	706,500	2.0 years	$26.98	189,500	$23.35

The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants.

6. ACCUMULATED OTHER COMPREHENSIVE INCOME

Three months ended March 31, 2007

	Opening	Other Comprehensive Income	Ending
Unrealized gains and losses on available-for sale financial assets	$1,566,000	$ 982,000	$2,548,000
Unrealized gains and losses on derivatives designated as cash flow hedges	814,000	(1,242,000)	(428,000)
	$2,380,000	$ (260,000)	$2,120,000

7. RELATED PARTY TRANSACTIONS

The Trust received a management fee from Comaplex of $75,000 (2006 - $75,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses. The above charge represents the fair value of the services rendered. As at March 31, 2007 the Trust had an account receivable from Comaplex of $53,000 (December 31, 2006 - $38,000).

The Trust received a management fee from Pine Cliff Energy Ltd. (Pine Cliff) of $54,000 (2006 - $54,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses. As at March 31, 2007 the Trust had nominal accounts receivable from or accounts payable to Pine Cliff. The above charge represents the fair value of the services rendered.

8. COMMITMENTS – FUTURE SALES AGREEMENTS

The Trust entered into the following commodity hedging contracts for a portion of its 2007 and 2008 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
Jan. 1, 2007 to June 30, 2007	Crude Oil	500 barrels	WTI	Floor of $74.55 and ceiling of $85.00 per barrel
Jan. 1, 2007 to June 30, 2007	Crude Oil	500 barrels	WTI	Floor of $75.00 and ceiling of $95.47 per barrel
July 1, 2007 to Dec. 31, 2007	Crude Oil	500 barrels	WTI	Floor of $75.00 and ceiling of $93.00 per barrel
July 1, 2007 to Dec. 31, 2007	Crude Oil	500 barrels	WTI	Floor of $70.00 and ceiling of $80.06 per barrel
Jan. 1, 2008 to June 30, 2008	Crude Oil	1,000 barrels	WTI	Floor of $73.00 and ceiling of $83.00 per barrel
April 1, 2007 to July 31, 2007	Natural Gas	2,000 GJ's	AECO	$6.52 per GJ
April 1, 2007 to Oct. 31, 2007	Natural Gas	1,000 GJ's	AECO	Floor of $6.50 and ceiling of $9.20 per GJ
Nov. 1, 2007 to March 31, 2008	Natural Gas	2,000 GJ's	AECO	Floor of $6.50 and ceiling of $10.37 per GJ

9. SUBSEQUENT EVENT – DISTRIBUTION

Subsequent to March 31, 2007, the Trust declared distributions of $0.22 per unit payable on April 30 and May 31, 2007 to Unitholders of record on April 16 and May 15, 2007 respectively. The distribution represents funds flow in the Trust for the months of March and April 2007.

Bonterra
Energy Income Trust

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