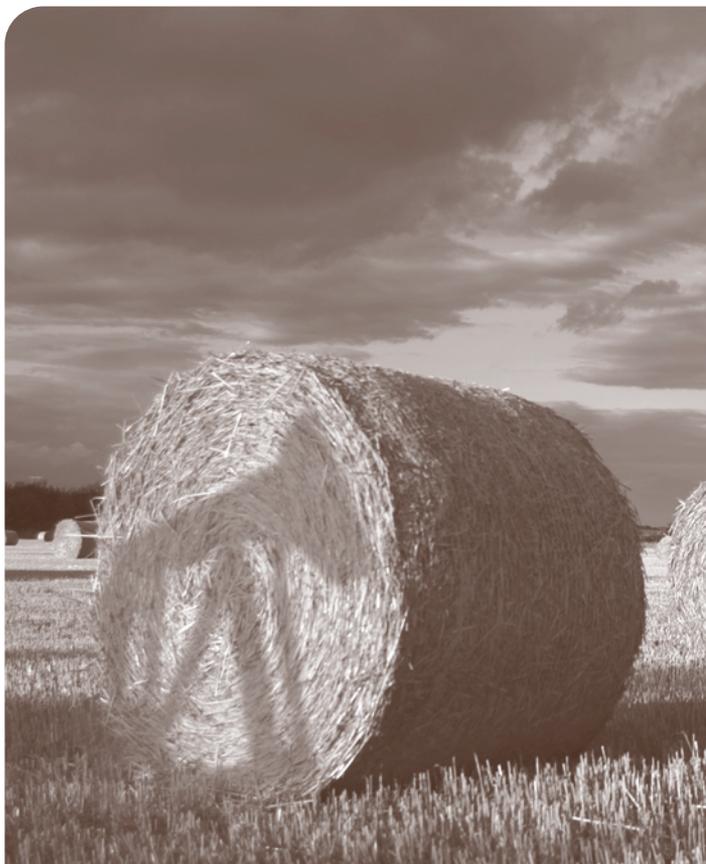




**Q2**

2007 INTERIM REPORT

*For the Period Ended June 30, 2007*





## Highlights

	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2007	2006	2007	2006
<b>Financial</b> (\$000, except \$ per unit)				
Revenue – oil and gas	<b>23,462</b>	23,219	<b>46,064</b>	43,350
Funds Flow from Operations <sup>(1)</sup>	<b>11,695</b>	14,008	<b>24,824</b>	26,161
Per Unit - Basic	<b>0.69</b>	0.84	<b>1.47</b>	1.57
Per Unit - Diluted	<b>0.69</b>	0.83	<b>1.47</b>	1.56
Net Earnings	<b>4,440</b>	10,617	<b>13,344</b>	20,338
Per Unit - Basic	<b>0.26</b>	0.64	<b>0.79</b>	1.22
Per Unit - Diluted	<b>0.26</b>	0.63	<b>0.79</b>	1.21
Cash Distributions per Unit	<b>0.66</b>	0.69	<b>1.32</b>	1.38
Capital Expenditures and Acquisitions	<b>1,699</b>	6,246	<b>9,324</b>	16,294
Total Assets			<b>139,432</b>	122,166
Working Capital Deficiency <sup>(2)</sup>			<b>49,595</b>	28,820
Unitholders Equity			<b>51,920</b>	61,202
<b>Operations</b>				
Oil and NGL's				
Barrels Per Day	<b>3,074</b>	3,001	<b>3,150</b>	2,999
Average Price (\$ per barrel)	<b>67.60</b>	69.90	<b>65.02</b>	63.46
Natural Gas				
MCF Per Day	<b>6,663</b>	6,181	<b>6,567</b>	6,127
Average Price (\$ per MCF)	<b>7.40</b>	7.16	<b>7.46</b>	7.83
Total Barrels per Day	<b>4,185</b>	4,031	<b>4,245</b>	4,020

- (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 August 8, 2007 is a review of the operations, current financial position and outlook for Bonterra Energy Income Trust and should be read in conjunction with the unaudited financial statements for the six months ended June 30, 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 Energy Income Trust ("Bonterra" or "the Trust") is pleased to report its results for the first half of 2007. Oil and natural gas revenue increased by six percent from \$43,350,000 in the 2006 six month period to \$46,064,000 for the 2007 six month period. The increase is mainly attributable to an increase in production volumes of 5.6 percent to 4,245 barrels of oil equivalent (BOE's) from 4,020 BOE's for the comparable six month period.

Funds flow from operations and net earnings decreased by 5 and 34 percent respectively

in 2007 compared to the results from the first half of 2006. Both reductions were principally due to one time issues that related to prior years and the first quarter of 2007 and were all recorded in the second quarter of 2007. The one time issues that affected net earnings and fund flow from operations consisted of an approximately \$850,000 royalty adjustment for 2005, 2006 and Q1 2007 and extra operating costs and reworking costs to existing producing and non-producing wells that will assist in increased production volumes in future quarters.

Other cash items that had a negative impact on funds flow and net earnings were an approximate \$1,000,000 increase in operating costs, an interest expense increase of \$787,000 and the elimination of Alberta royalty tax credits resulting in a reduction of revenue of \$335,000 and no gain on sale of property in 2007 compared to a 2006 gain of \$532,000.

These negatives more than offset the increase in oil and gas revenues (including hedging adjustments) of \$2,714,000 and the reduction of general and administrative costs of \$153,000. Net earnings were also affected by an increase in non-cash items of \$1,279,000 of depletion, depreciation and accretion, dry hole costs of \$476,000 and additional future income taxes of \$3,864,000 (resulting mainly from the Federal Governments legislated change in how Trusts will be taxed).

The above items also had an impact on the payout ratio for the first six months of 2007 resulting in a payout ratio of 90 percent compared to an objective of 80 percent. Production increases and the elimination of one time charges during the last half of 2007 should assist in improving upon this ratio. Obviously commodity prices will influence funds flow as well. Bonterra's production consists of approximately 65 percent light sweet gravity crude and therefore may not be impacted too much by the projected lower natural gas prices.

At June 30, 2007, Bonterra had 7 gross (4.8 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. The Trust does not anticipate the completion and tie-in of the CBM wells will occur until sometime in 2008.

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, recompletions 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. Exceedingly wet weather during the second quarter delayed the implementation of the above however, despite reducing the capital expenditure budget for 2007 to \$20 million from \$38 million in 2006 and the delay; Bonterra may still grow its production volumes by conducting these types of programs during the balance of the year.

With regard to dealing with the federal taxation changes that were announced on October 31, 2006 and now have been legislated, Bonterra is evaluating the implications and various alternatives that are available to mitigate the impact of the additional taxes commencing in 2011. One of the difficult issues that has to be dealt with is that Bonterra has three types of unitholders that are affected differently; being Canadian resident unitholders that hold the units outside of tax shelters, Canadian resident unitholders that hold units within tax shelters and foreign unitholders. Generally what is beneficial for one type of unitholder may be detrimental to other types of unitholders.

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<sub>2</sub> sequestration, and by reworking and refracing existing producing and suspended wells.

## Financial and Operational Discussion

<i>Quarterly Comparisons</i>	2007			2006		
	2nd	1st	4th	3rd	2nd	1st
<b>Financial</b> (\$000, except \$ per unit)						
Revenue - oil and gas	<b>23,462</b>	22,602	21,719	23,665	23,219	20,131
Funds Flow from Operations <sup>(1)</sup>	<b>11,695</b>	13,129	12,235	14,401	14,008	12,153
Per Unit Basic	<b>0.69</b>	0.78	0.72	0.86	0.84	0.73
Per Unit Fully Diluted	<b>0.69</b>	0.78	0.72	0.85	0.83	0.72
Net Earnings	<b>4,440</b>	8,904	6,471	10,441	10,617	9,721
Per Unit Basic	<b>0.26</b>	0.53	0.39	0.62	0.64	0.58
Per Unit Fully Diluted	<b>0.26</b>	0.53	0.38	0.62	0.63	0.58
Cash Distributions	<b>0.66</b>	0.66	0.72	0.72	0.69	0.69
Capital Expenditures and Acquisitions	<b>1,699</b>	7,625	9,457	12,597	6,246	10,048
Total Assets	<b>139,432</b>	140,926	134,942	130,655	122,166	118,439
Working Capital Deficiency	<b>49,595</b>	49,288	50,187	38,853	28,820	25,532
Unitholders' Equity	<b>51,920</b>	57,646	53,359	60,387	61,202	61,365
<b>Operations</b>						
Oil and Liquids (barrels per day)	<b>3,074</b>	3,227	3,138	3,024	3,001	2,996
Natural Gas (MCF per day)	<b>6,663</b>	6,470	5,885	5,925	6,181	6,071
2005						
4th						
3rd						
2nd						
1st						
<b>Financial</b> (\$000, except \$ per unit)						
Revenue - oil and gas			21,753	20,532	17,114	16,438
Funds Flow from Operations <sup>(1)</sup>			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
<b>Operations</b>						
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 six months ended June 30, 2007 was 4,245 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 3,150 barrels per day of crude oil and natural gas liquids and 6,567 MCF per day of natural gas. Bonterra's first half 2006 average production was 4,020 BOE's per day consisting of 2,999 barrels per day of crude oil and natural gas liquids and 6,127 MCF per day of natural gas.

The Trust drilled 7 gross (6.4 net) Cardium oil wells and 2 gross (0.7 net) shallow gas wells in the first six months of 2007 on its operated lands. As at June 30, 2007 Bonterra had 7 gross (4.8 net) Cardium oil wells, 12 gross (9 net) natural gas wells and 7 gross (5.5 net) coal-bed wells drilled but not on production on its operated lands. During the first six months of 2007, the Trust tied-in 11 gross (10.7 net) Cardium wells and 2 gross (1 net) natural gas wells on its operated lands.

Management anticipates that all the currently drilled but not producing Cardium wells will be completed and tied-in by the end of the third quarter of 2007. Seven gross (4.1 net) of the natural gas wells are anticipated to be completed and tied-in by the end of the third quarter of 2007. The remaining shallow gas wells and coal-bed methane wells will not be completed and tied-in in 2007 for various reasons, including landowner issues, regulatory factors, gathering system capacity and line pressure issues.

The Trust has been active in reworking existing natural gas wells resulting in significant increases to production without the necessity of drilling further wells. Production gains from such reworks as well as solution gas from the newly completed Cardium oil wells has resulting in the majority of the natural gas production increases in the first half of 2007. Overall production rates in the second quarter of 2007 were affected by normal spring break up conditions resulting in the inability to perform maintenance on wells as well as higher initial declines in production on the newly completed Cardium oil wells which is a normal happening for new Cardium wells.

## Revenue

Revenue from petroleum and natural gas sales was \$46,064,000 (2006 - \$43,350,000). The increase in revenue over the 2006 first half was primarily due to additional production from the wells drilled during 2006. The average price received for crude oil and natural gas liquids during the first six months of 2007 was \$65.02 (\$67.60 in the second quarter) per barrel and \$7.46 (\$7.40 in the second quarter) per MCF for natural gas compared to \$63.46 per barrel and \$7.83 per MCF in

the corresponding 2006 period. On a quarter over quarter basis, revenue increased by \$860,000 due primarily to increased crude oil prices from first quarter pricing of \$62.53 offset partially by reduced production volumes.

Gross revenue has been increased by \$815,000 (2006 decreased by \$1,091,000) 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 production that has high operating costs 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 Notes 9 and 10 to the attached interim financial statements for present hedging details. At June 30, 2007, the fair value of the outstanding commodity hedging contracts was a net asset of \$710,000 (December 31, 2006 - \$1,189,000).

### **Royalties**

During the second quarter of 2007, two significant royalty adjustments were recorded. Firstly, the Trust discovered that the production limit resulting in additional gross overriding royalty in respect of certain of its Cardium oil wells had been reached. The production limit was calculated on a multitude of Cardium wells including several that were not owned by the Trust. In addition the exact wells that the production limit was applicable to was not readily known by the Trust nor easily calculated. In discussions with the payee it was determined that the production limit was reached in late 2005. The royalty has been calculated based on this agreed date and the affected wells for Bonterra and other operators in the area were identified. The approximate amount of the adjustment, net to the Trust is \$700,000 for periods prior to April 1, 2007. The monthly amount of the royalty on a go forward basis is approximately \$40,000 per month based on current pricing and production levels.

Secondly, the Trust was informed by the operator of one of its non-operated properties that it had not charged a net profit royalty for the years 2004, 2005 and 2006. In review of the agreements it was confirmed no payment was made and an amount of approximately \$150,000 was accrued by the Trust for payment of such net profit royalty.

Royalties paid by the Trust consist of Crown royalties paid to the Provinces of Alberta and Saskatchewan as well as numerous gross override and freehold royalties. During the first six months of 2007 the Trust paid \$4,545,000 (2006 - \$4,389,000) in Crown royalties and \$1,901,000, which includes the above described adjustments of \$700,000 and \$150,000, (2006 - \$1,062,000) 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 2.5 percent (after adjusting for the one time items discussed above) (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 by the Alberta Government effective January 1, 2007 which resulted in a reduction of revenue of \$335,000 in 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 six months ended June 30, 2007 were \$12,137,000 compared to \$10,552,000 for the six months ended June 30, 2006. On a BOE basis production costs averaged \$15.80 in 2007 (\$17.21 in Q2) versus \$14.50 in the corresponding 2006 period. Production costs in Q2 increased \$975,000 over Q1 due to the Trust performing numerous maintenance programs on its oil producing facilities and pipelines and the operator of a number of the Trusts gas plants performed their annual turnarounds. In addition a number of natural gas production optimizations were performed and the costs associated with this program were expensed. These optimizations should result in increased production volumes in the future. The balance of the increase on a year over year basis is due to higher prices being charged by the oil and gas service industry.

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 12.5 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 \$1,091,000 (\$527,000 in the second quarter) in the first half of 2007 compared to \$1,244,000 in the six months ended June 30, 2006 and

\$564,000 in the three months ended March 31, 2007. Costs on a BOE bases decreased to \$1.44 per BOE in the first half of 2007 compared to \$1.71 per BOE in the first half of 2006. The decrease in general and administrative expenses year over year was due primarily to approximately a \$140,000 decrease in third party consulting fees. Increases in employee salary compensation were offset by reduced bonus accruals and a general reduction in overall office expenditures. The quarter over quarter amounts were not significantly different other than annual report and filing costs for the year were incurred in the first quarter.

### **Interest Expense**

Interest expense increased to \$1,441,000 (\$744,000 in the second quarter) for the six months ended June 30, 2006 compared to \$654,000 for the six months ended June 30, 2006 and \$697,000 for the first quarter of 2007. Increased average debt levels and increased interest rates were the primary factors for the increase in interest expense. The Trust's average borrowing rate for 2007 was approximately 5.6 percent compared to 5 percent for the first six months of 2006. The Trust's net debt as a percentage of annualized second quarter funds flow was approximately twelve and three quarter months which is slightly higher than the Trust's goal of one year.

The Trust's bank loan of \$54,601,000 increased by approximately \$9.2 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 Trust's winter 2007 drill program of \$9,324,000 which represents 47 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.

The Trust issued 522,000 unit options of which 517,000 were issued at the end of June 2007 at an average price of \$28.30 and a fair value of \$2.74 per unit. The fair value of the options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 4.7 (2006 – 4.1) percent, expected weighted average volatility of 27 percent (2006 – 27), expected weighted average life of 2.5 years (2006 – 2.5) and an annual dividend rate based on the distributions paid to the Unitholders during the year. As the options were issued at the end of the quarter no significant expense in relation to these options was recorded in Q2. The future unit based compensation impact of these options is approximately \$235,000 per quarter over the next five quarters.

## Depletion, Depreciation and Accretion

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 \$6,786,000 and \$5,507,000 for the six month periods ending June 30, 2007 and June 30, 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. The decrease in Q2 of \$218,000 from Q1 depletion amounts was due to reduced production volumes.

Dry hole costs of \$476,000 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 half of 2007.

## Income Taxes

On October 31, 2006, the Canadian Federal Government announced a proposed Trust taxation pertaining to taxation of distributions paid by publicly traded income trusts and this was enacted by legislation in June 2007. Previously, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and is paid by the unitholders. The June, 2007 legislation results in a two-tiered tax structure whereby distributions commencing in 2011 would first be subject to a 31.5 percent at the Trust level tax and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation.

Future income tax expense for the period increased by a one time adjustment of \$3,801,000, with a corresponding increase to the future tax liability, upon the June 2007 enactment. Until June 2007, the Trust had been tax effecting the reversal of taxable temporary differences at a nil tax rate on the assumption that the Trust would make sufficient tax deductible cash distributions to unitholders such that the Trust's taxable income would be nil for the foreseeable future and the tax burden would have continued to be with whomever received the monthly distribution. The new legislation limits the tax deductibility of cash distributions such that income taxes may become payable in the future.

The Trust has estimated its future income taxes based on its best estimates of results

from operations and tax pool claims and cash distributions in the future assuming no material change to the Trust's current organizational structure. As currently interpreted, Canadian Generally Accepted Accounting Principles ("GAAP") does not permit the Trust's estimate of future income taxes to incorporate any assumptions related to a change in organizational structure until such structures are given legal effect even though it is anticipated that many trusts will change their organizational structure to attempt to reduce this impact.

The Trust's estimate of its future income taxes will vary as to the Trust's assumptions pertaining to the factors described above, and such variations may be material.

Until 2011, the new legislation does not directly affect the Trust's funds flow from operations, and accordingly, the Trust's financial condition.

Currently 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.

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	\$16,105,000
Canadian oil and gas property expenditures	10	1,182,000
Canadian development expenditures	30	35,187,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward <sup>(1)</sup>	100	9,035,000
		\$61,602,000

<sup>(1)</sup>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	\$14,950,000
Finance costs	20	483,000
Eligible capital expenditures	7	162,000
		\$15,595,000

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

### Net Earnings

Net earnings decreased to \$13,344,000 in the first six months of 2007 from \$20,338,000 in the corresponding 2006 period. Revenue increases due to increased production volumes were generally offset by increased operating costs, interest expense, depletion, depreciation accretion and dry hole costs, and provision for future income taxes. The Trust's quarter over quarter net earnings decreased by \$4,464,000 primarily due to these combined items and are explained in detail in various sections of this report.

### Comprehensive Income

On January 1, 2007 the Trust became obliged to adopt 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 hedging 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 six months included an increase in the unrealized gain on investment in a related party of \$628,000, a reduction of \$577,000 relating to the recognition and transfer of previously reported gains in accumulated other comprehensive income and a gain of \$266,000 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.

### Standardized Distributable Cash

#### *Compliance with Guidance*

The following Management, Discussion and Analysis is in all material respects in accordance with the recommendations provided in CICA's publication *Standardized Distributable Cash in Income Trusts and Other Flow-Through Entities: Guidance on Preparation and Disclosure*. All trusts will be obligated to adopt these recommendations commencing with the third quarter of 2007. Bonterra has decided to commence with these changes for this report.

*Definition and Disclosure of Standardized Distributable Cash*

	<b>Six Months Ended June 2007</b>	Six Months Ended June 2006	Cumulative Amounts From Inception of Trust (July 1, 2001)
Cash Cash Flow from			
Operating Activities	<b>\$26,178,000</b>	\$25,921,000	\$166,842,000
Less adjustment for:			
Capital expenditures	<b>(9,324,000)</b>	(16,294,000)	(75,198,000)
Financing restrictions caused by debt	–	–	–
<b>Standardized Distributable Cash</b>	<b>\$16,854,000</b>	\$ 9,627,000	\$92,473,000

*Definition and Disclosure of Adjusted Distribution Base (Formerly Funds Flow from Operations)*

	<b>Six Months Ended June 2007</b>	Six Months Ended June 2006	Cumulative Amounts From Inception of Trust (July 1, 2001)
<b>Standardized Distributable Cash</b>			
– per above	<b>\$16,854,000</b>	\$ 9,627,000	\$92,473,000
Adjusted for:			
Capital expenditures	<b>9,324,000</b>	16,294,000	75,198,000
Gain on sale of property	–	532,000	1,089,000
Changes in accounts receivable	<b>(599,000)</b>	(290,000)	4,494,000
Changes in crude oil inventory	<b>(65,000)</b>	153,000	304,000
Changes in parts inventory	<b>(24,000)</b>	4,000	(208,000)
Changes in prepaid expenses	<b>454,000</b>	531,000	254,000
Changes in accounts payable and accrued liabilities	<b>(1,429,000)</b>	(815,000)	1,594,000
Asset retirement obligations settled	<b>309,000</b>	125,000	1,709,000
<b>Adjusted Distribution Base (formerly Funds Flow from Operations)<sup>(1)</sup></b>	<b>\$24,824,000</b>	\$26,161,000	\$176,907,000

<sup>(1)</sup> 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.

## Working Capital Policies

The Trust, excluding current portion of debt, maintains a consistent level of working capital. All items of working capital are generally turned over every 30 to 60 days. Excluding minor variations due to payment of bonuses and property taxes there are no recurring items that would cause a seasonal impact in working capital.

## Analysis of Relationship between Standardized Distributable Cash, Distributions, and Investing and Financing Activities

	<b>Six Months Ended June 2007</b>	Year ended December 31, 2006	Year ended December 31, 2005	Year ended December 31, 2004
<b>Standardized Distributable</b>				
Cash	<b>\$16,854,000</b>	\$13,596,000	\$22,316,000	\$18,875,000
Distributions <sup>(1)</sup>	<b>(\$22,309,000)</b>	(\$47,281,000)	(\$38,949,000)	(\$27,088,000)
Increase in bank debt	<b>\$9,222,000</b>	\$25,202,000	\$11,717,000	(\$17,969,000)
<b>Proceeds on issuance of</b>				
employee unit options	<b>\$705,000</b>	\$5,161,000	\$2,823,000	\$3,292,000
<b>Issuance of units</b>				
(net of costs of issue)	-	-	(\$259,000)	\$20,272,000
Proceeds on sale of properties	-	\$750,000	\$1,097,000	-
<b>Non cash financing and investing working capital adjustments</b>				
	<b>(\$4,472,000)</b>	\$2,572,000	\$1,255,000	\$2,618,000

<sup>(1)</sup> Includes distribution declared in July in respect of June operations.

The only unfunded operating transaction of the Trust is its asset retirement obligations. The Trust has the following estimated timing of expenditures for asset retirement obligations:

Year	Expected Expenditure
2007 (including expenditures incurred to date)	\$421,000
2008	494,000
2009	398,000
2010	986,000
2011	805,000
	<b>\$3,104,000</b>

## Definition and History of Productive Capacity and Strategy

Bonterra's primary objective is to grow its reserves from which it expects to continue with 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.

	<b>Six Months Ended June 2007</b>	Year ended December 31, 2006	Year ended December 31, 2005	Year ended December 31, 2004
Proven and probable reserves at beginning of period (BOE's)	<b>26,476,000</b>	23,870,000	19,711,000	16,529,000
Reserves added due to acquisitions (BOE's)	-	16,000	2,393,000	-
Reserves added due to capital expenditures (BOE's)	<sup>(1)</sup>	4,082,000	3,100,000	4,351,000
Production during period (BOE's)	<b>757,000</b>	1,476,000	1,334,000	1,169,000
Increase in productive capacity (BOE's)	<sup>(1)</sup>	2,606,000	4,159,000	3,182,000
Reserves per unit (fully diluted)	<b>1.52<sup>(2)</sup></b>	1.57	1.46	1.39
Productive capacity maintenance requirements	<b>\$12,043,000</b>	\$17,472,000	\$9,205,000	\$3,460,000
Capital expenditures for the period	<b>\$9,324,000</b>	\$38,348,000	\$56,703,000	\$10,595,000
Capital expenditures in excess of maintenance requirements	<b>(\$2,719,000)</b>	\$20,876,000	\$47,498,000	\$7,135,000
Cost of increased productive capacity (per BOE)	<sup>(1)</sup>	\$8.01	\$11.42	\$2.24

<sup>(1)</sup> The Trust does not update reserve information quarterly

<sup>(2)</sup> Assuming no additional reserves in 2007.

## Financing Strategy

The Trust maintains a strategy of limiting its debt levels to approximately one year funds flow. Bonterra has a long term goal to retain between 15 to 20 percent of its funds flow to finance its capital maintenance expenditures. Over the past years, this level of retention of

funds has proven to be sufficient to amply maintain the productive capacity of the Trust. To the extent additional capital expenditures are incurred to increase reserves, the Trust anticipates financing them through proceeds received on exercise of employee unit options, equity placements or from its line of credit.

Periods may exist where the cost of replacing reserves exceed the level of funds withheld. However, the Trust with its long life reserves and relatively low debt levels compared to other income trusts has the flexibility to increase or decrease its capital commitments depending on commodity prices and costs of development.

It is management's strategy to finance the costs of reclamation as well as potential income taxes (commencing in 2011) resulting from the recently enacted income trust tax law from funds flow. Management is reviewing various organizational alternatives and operational strategies to mitigate the impact of the new tax.

### Compliance with Financial Covenants

Due to the relatively low debt levels maintained by the Trust, the Trust's loan agreements do not contain any debt covenants, other than the debt is payable upon demand.

### Per Unit and Ratio Disclosures

	Six Months Ended June 2007	Six Months Ended June 2006	Cumulative Amounts From Inception of Trust (July 1, 2001)
Standardized Distributable Cash			
– per above	<b>\$16,854,000</b>	\$ 9,627,000	\$92,473,000
Per weighted average unit	<b>\$1.00</b>	\$0.58	\$6.17
Per fully diluted unit	<b>\$1.00</b>	\$0.57	\$6.11
Cash distributions <sup>(1)</sup>	<b>\$22,309,000</b>	\$23,042,000	\$159,651,000
Payout ratio	<b>1.32</b>	2.39	1.73
Adjusted Distribution Base	<b>\$24,824,000</b>	\$26,161,000	\$176,907,000
Per weighted average unit	<b>\$1.47</b>	\$1.57	\$11.81
Per fully diluted unit	<b>\$1.47</b>	\$1.56	\$11.69
Cash distributions <sup>(1)</sup>	<b>\$22,309,000</b>	\$23,042,000	\$159,651,000
Payout ratio	<b>0.90</b>	0.88	0.90

<sup>(1)</sup> Includes distribution declared in July 2007 and 2006 in respect of June 2007 and 2006 operations respectively.

On a go forward basis the Trust plans to reduce the payout ratio in respect of Standardized Distributable Cash to a level between 110 to 120 percent to facilitate a debt to cash 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 cash flow from wells currently drilled but not tied in.

### Tax Attributes of Distributions and the Trust's Assets

See discussion under Income Taxes.

#### Cash Netback

The following table illustrates the Trust's cash netback for the six month periods ended (The 2007 netback includes one time charges to royalties and field operating costs as described above in this report):

	<b>June 30</b>	June 30
\$ per Barrel of Oil Equivalent (BOE)	<b>2007</b>	2006
Production volumes (BOE)	<b>757,485</b>	727,620
Gross production revenue	<b>\$60.81</b>	\$59.58
Royalties	<b>(8.51)</b>	(7.49)
Field operating	<b>(15.80)</b>	(14.50)
Field netback	<b>36.50</b>	37.59
General and administrative	<b>(1.44)</b>	(1.71)
Interest and taxes	<b>(2.11)</b>	(1.16)
Cash netback	<b>\$32.95</b>	\$34.72

The following table illustrates the Trust's cash netback for the three month periods ended (The June 30 netback includes one time charges to royalties and field operating costs as described above in this report):

	<b>June 30</b>	March 31
\$ per Barrel of Oil Equivalent (BOE)	<b>2007</b>	2007
Production volumes (BOE)	<b>370,031</b>	387,454
Gross production revenue	<b>\$63.41</b>	\$58.33
Royalties	<b>(10.45)</b>	(6.65)
Field operating	<b>(17.21)</b>	(14.40)
Field netback	<b>35.75</b>	37.28
General and administrative	<b>(1.42)</b>	(1.46)
Interest and taxes	<b>(2.24)</b>	(1.99)
Cash netback	<b>\$32.09</b>	\$33.83

## Related Party Transactions

The Trust received a management fee from Comaplex Minerals Corp., a company with common directors and management, of \$150,000 (2006 - \$150,000) 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 \$108,000 (2006 - \$108,000) 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 half of 2007, the Trust incurred capital costs of \$9,324,000. The Trust drilled 7 gross (6.4 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) 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 June 30, 2007 (December 31, 2006 - \$49,900,000). Subsequent to the end of Q2 the Trust increased its credit facility to \$69,900,000. The credit facilities carry 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 six 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	41,000	705,000
Transfer of contributed surplus to unit capital	–	74,000
Balance, June 30, 2007	16,915,658	\$90,267,000

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,691,000 (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 June 30, 2007 and December 31, 2006, and changes during the six month and twelve month periods ending on those dates is presented below:

	June 30, 2007		December 31, 2006	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	<b>721,500</b>	<b>\$26.55</b>	646,000	\$18.67
Options granted	<b>546,000</b>	<b>28.12</b>	447,000	29.18
Options exercised	<b>(41,000)</b>	<b>17.19</b>	(339,500)	15.20
Options cancelled	<b>(40,000)</b>	<b>28.21</b>	(32,000)	24.70
Outstanding at end of period	<b>1,186,500</b>	<b>\$27.54</b>	721,500	\$26.55
Options exercisable at end of period	<b>209,500</b>	<b>\$23.73</b>	212,500	\$22.62

The following table summarizes information about unit options outstanding at June 30, 2007:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number Outstanding At 6/30/07	Weighted- Average Remaining Contractual Life	Number Weighted- Average Exercise Price	Exercisable At 6/30/07	Weighted- Average Exercise Price
	\$22.45-\$23.35	237,500	1.7 years	\$23.32	194,500
\$24.20-\$25.00	24,000	2.6 years	24.34	—	—
\$26.60	5,000	2.6 years	26.60		
\$28.30-\$28.75	880,000	2.4 years	28.49	15,000	28.72
\$32.00-\$33.75	40,000	2.5 years	33.55	—	—
\$22.45-\$33.75	1,186,500	2.3 years	\$27.54	209,500	\$23.73

### 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, they 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](http://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 June 30, 2007 (unaudited) and December 31, 2006

**2007**

2006

### Assets

#### Current

Accounts receivable	<b>\$ 8,894,000</b>	\$ 10,486,000
Crude oil inventory	<b>778,000</b>	843,000
Parts inventory	<b>90,000</b>	114,000
Prepaid expenses	<b>1,540,000</b>	1,086,000
Derivative asset (Note 1)	<b>710,000</b>	–
Investments in related party (Notes 1 and 2)	<b>3,035,000</b>	461,000
	<b>15,047,000</b>	12,990,000

#### Property and Equipment (Note 3)

Petroleum and natural gas properties and related equipment	<b>185,034,000</b>	176,602,000
Accumulated depletion and depreciation	<b>(60,649,000)</b>	(54,650,000)

<b>Net Property and Equipment</b>	<b>124,385,000</b>	121,952,000
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	<b>\$ 139,432,000</b>	\$ 134,942,000
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### Liabilities

#### Current

Distribution payable	<b>\$ –</b>	\$ 4,050,000
Accounts payable and accrued liabilities	<b>10,041,000</b>	13,748,000
Debt (Note 4)	<b>54,601,000</b>	45,379,000
	<b>64,642,000</b>	63,177,000

<b>Future Income Tax Liability (Note 5)</b>	<b>7,989,000</b>	3,587,000
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<b>Asset Retirement Obligations</b>	<b>14,881,000</b>	14,819,000
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	<b>87,512,000</b>	81,583,000
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#### Commitments (Notes 9 and 10)

#### Unitholders' Equity (Note 6)

Unit capital	<b>90,267,000</b>	89,488,000
Contributed surplus	<b>1,445,000</b>	1,116,000
	<b>91,712,000</b>	90,604,000

Deficit	<b>(42,489,000)</b>	(37,245,000)
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Accumulated other comprehensive income (Note 7)	<b>2,697,000</b>	–
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	<b>(39,792,000)</b>	(37,245,000)
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	<b>51,920,000</b>	53,359,000
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	<b>\$ 139,432,000</b>	\$ 134,942,000
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## Consolidated Statements of Operations and Deficit

For the periods ended June 30 (unaudited)

	Three Months		Six Months	
	2007	2006	2007	2006
<b>Revenue</b>				
Oil and gas sales	\$23,237,000	\$23,395,000	\$45,249,000	\$44,441,000
Hedging gain (loss)	225,000	(176,000)	815,000	(1,091,000)
Royalties	(3,868,000)	(2,872,000)	(6,446,000)	(5,451,000)
Gain on sale of property	—	—	—	532,000
Alberta royalty tax credits	—	159,000	—	335,000
Interest and other	12,000	28,000	33,000	35,000
	<b>19,606,000</b>	20,534,000	<b>39,651,000</b>	38,801,000
<b>Expenses</b>				
Production costs	6,556,000	5,400,000	12,137,000	10,552,000
General and administrative	527,000	612,000	1,091,000	1,244,000
Interest on debt	744,000	423,000	1,441,000	654,000
Unit based compensation	185,000	207,000	403,000	365,000
Dry hole costs	9,000	—	476,000	—
Depletion, depreciation and accretion	3,284,000	2,910,000	6,786,000	5,507,000
	<b>11,305,000</b>	9,552,000	<b>22,334,000</b>	18,322,000
<b>Earnings before Income Taxes</b>	<b>8,301,000</b>	10,982,000	<b>17,317,000</b>	20,479,000
<b>Income Taxes (Recovery)</b>				
Current	84,000	91,000	158,000	190,000
Future	3,777,000	274,000	3,815,000	(49,000)
	<b>3,861,000</b>	365,000	<b>3,973,000</b>	141,000
<b>Net Earnings for the Period</b>	<b>4,440,000</b>	10,617,000	<b>13,344,000</b>	20,338,000
Deficit at beginning of period	(35,767,000)	(25,146,000)	(37,245,000)	(27,214,000)
Distributions declared	(11,162,000)	(11,536,000)	(18,588,000)	(19,189,000)
<b>Deficit at End of Period</b>	<b>(\$42,489,000)</b>	(\$26,065,000)	<b>(42,489,000)</b>	(26,065,000)
<b>Net Earnings per Trust Unit –</b>				
<b>Basic (Note 6)</b>	<b>\$0.26</b>	\$0.64	<b>\$0.79</b>	\$1.22
<b>Net Earnings per Trust Unit –</b>				
<b>Diluted (Note 6)</b>	<b>\$0.26</b>	\$0.63	<b>\$0.79</b>	\$1.21

## Consolidated Statements of Unitholders' Equity

For the periods ended June 30 (unaudited)	Three Months		Six Months	
	2007	2006	2007	2006
Unitholders' equity,				
beginning of period	\$57,646,000	\$61,365,000	\$53,359,000	\$57,322,000
Comprehensive income for the period	5,017,000	10,617,000	13,661,000	20,338,000
Adjustment of opening accumulated comprehensive income (Note 1)	—	—	2,380,000	-
Net capital contributions	234,000	549,000	705,000	2,366,000
Unit based compensation adjustment	185,000	207,000	403,000	365,000
Distributions declared	(11,162,000)	(11,536,000)	(18,588,000)	(19,189,000)
Unitholders' Equity, End of Period	\$51,920,000	\$61,202,000	\$51,920,000	\$61,202,000

## Consolidated Statements of Comprehensive Income

For the periods ended June 30 (unaudited)	Three Months	Six Months
	2007	2007
<b>Net Earnings for the Period</b>	<b>\$4,440,000</b>	<b>\$13,344,000</b>
<i>Other Comprehensive Income, net of tax</i>		
Unrealized gains and losses on investments (net of income taxes; Three Months ended - (\$61,000), Six Months ended - \$109,000)	(354,000)	628,000
Gains and losses on derivatives designated as cash flow hedges (net of income taxes; Three Months ended - \$491,000, Six Months ended - \$110,000)	1,193,000	266,000
Gains and losses on derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current period (net of income taxes; Three Months ended - \$109,000, Six Months ended - \$238,000)	(262,000)	(577,000)
Changes in gains and losses on derivatives designated as cash flow hedges (net of income taxes; Three Months ended - \$382,000, Six Months ended - (\$128,000))	931,000	(311,000)
Other Comprehensive Income	577,000	317,000
Comprehensive Income	\$5,017,000	\$13,661,000

## Consolidated Statements of Cash Flows

For the periods ended June 30 (unaudited)	Three Months		Six Months	
	2007	2006	2007	2006
<b>Operating Activities</b>				
Net earnings for the period	\$4,440,000	\$10,617,000	\$13,344,000	\$20,338,000
Items not affecting cash				
Gain on sale of property	—	—	—	(532,000)
Unit based compensation	185,000	207,000	403,000	365,000
Dry hole costs	9,000	—	476,000	—
Depletion, depreciation and accretion	3,284,000	2,910,000	6,786,000	5,507,000
Future income taxes	3,777,000	274,000	3,815,000	(49,000)
	<b>11,695,000</b>	<b>14,008,000</b>	<b>24,824,000</b>	<b>25,629,000</b>
Change in non-cash working capital				
Accounts receivable	60,000	15,000	599,000	290,000
Crude oil inventory	79,000	(26,000)	65,000	(153,000)
Parts inventory	16,000	(79,000)	24,000	(4,000)
Prepaid expenses	(502,000)	(406,000)	(454,000)	(531,000)
Accounts payable and accrued liabilities	2,326,000	522,000	1,429,000	815,000
Asset retirement obligations settled	(261,000)	(42,000)	(309,000)	(125,000)
	<b>1,718,000</b>	<b>(16,000)</b>	<b>1,354,000</b>	<b>292,000</b>
<b>Cash Provided by Operating Activities</b>				
	<b>13,413,000</b>	<b>13,992,000</b>	<b>26,178,000</b>	<b>25,921,000</b>
<b>Financing Activities</b>				
Increase in debt	1,766,000	4,302,000	9,222,000	11,342,000
Unit option proceeds	234,000	549,000	705,000	2,366,000
Unit distributions	(11,162,000)	(11,536,000)	(22,638,000)	(22,827,000)
<b>Cash Used in Financing Activities</b>	<b>(9,162,000)</b>	<b>(6,685,000)</b>	<b>(12,711,000)</b>	<b>(9,119,000)</b>
<b>Investing Activities</b>				
Property and equipment expenditures	(1,699,000)	(6,246,000)	(9,324,000)	(16,294,000)
Proceeds on sale of properties	—	—	—	750,000
Change in non-cash working capital				
Accounts receivable	729,000	270,000	993,000	(721,000)
Accounts payable and accrued liabilities	(3,281,000)	(1,331,000)	(5,136,000)	(537,000)
<b>Cash Used in Investing Activities</b>	<b>(4,251,000)</b>	<b>(7,307,000)</b>	<b>(13,467,000)</b>	<b>(16,802,000)</b>
<b>Net Cash Inflow</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>—</b>
Cash, beginning of period	—	—	—	—
<b>Cash, End of Period</b>	<b>\$—</b>	<b>\$—</b>	<b>\$—</b>	<b>\$—</b>
<b>Cash Interest Paid</b>	<b>\$744,000</b>	<b>\$423,000</b>	<b>\$1,441,000</b>	<b>\$654,000</b>
<b>Cash Taxes Paid (Recovered)</b>	<b>\$93,000</b>	<b>(\$506,000)</b>	<b>\$183,000</b>	<b>(\$394,000)</b>

## *Notes to the Interim Consolidated Financial Statements*

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Periods Ended June 30, 2007 and 2006 unaudited

### 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 Accountants' ("CICA") Handbook, "Financial Instruments – Recognition and Measurement" and Section 3861 Financial Instruments – Presentation and Disclosure. It sets out 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 financial 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,” whereby the only impact 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 June 30, 2007, was \$3,035,000 (December 31, 2006 - \$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

	June 30, 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	183,736,000	60,011,000	175,353,000	54,008,000
Furniture, equipment and other	964,000	638,000	915,000	642,000
	<b>\$185,034,000</b>	<b>\$60,649,000</b>	\$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 June 30, 2007 (December 31, 2006 - \$59,900,000). Subsequent to the end of the quarter, the Trust increased its bank facility to \$69,900,000. 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 June 30, 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 six month periods ended June 30, 2007 and 2006 for these loans were \$1,441,000 and \$654,000 respectively.

## 5. INCOME TAXES

The Trust has recorded a future income tax liability related to assets and liabilities and related tax amounts. The following figures reflect the consequences of the Canadian Federal Governments October 31, 2006 announcement on the future taxation of Income Trusts:

	<b>June 30, 2007</b>	December 31, 2006
Future income tax liability to assets and liabilities:	<b>\$10,701,000</b>	\$6,233,000
Future tax asset related to finance costs:	<b>(112,000)</b>	–
Future tax asset related to corporate tax losses carried forward in the subsidiary companies	<b>(2,600,000)</b>	(2,646,000)
	<b>\$ 7,989,000</b>	\$3,587,000

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

	<b>2007<sup>(1)</sup></b>	2006 <sup>(2)</sup>
Earnings before income taxes	<b>\$13,344,000</b>	\$20,338,000
Combined federal and provincial income tax rates	<b>0%</b>	34.97%
Income tax provision calculated using statutory tax rates	–	7,112,000
Increase (decrease) in taxes resulting from:		
Saskatchewan resource surcharge	<b>158,000</b>	190,000
Unit-based compensation	–	128,000
Non-deductible crown royalties	–	558,000
Resource allowance	–	(930,000)
Change in effective tax rate	<b>3,801,000</b>	–
Trust income allocated to Unitholders	–	(7,076,000)
Others	<b>(14,000)</b>	159,000
Income tax expense	<b>\$ 3,973,000</b>	\$ 141,000

<sup>(1)</sup> 2007 items calculated using trust effective tax rate

<sup>(2)</sup> 2006 items calculated using corporation effective tax rates

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	\$16,105,000
Canadian oil and gas property expenditures	10	1,182,000
Canadian development expenditures	30	35,187,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward <sup>(1)</sup>	100	9,035,000
		\$61,602,000

<sup>(1)</sup> 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	\$14,950,000
Finance costs	20	483,000
Eligible capital expenditures	7	162,000
		\$15,595,000

On October 31, 2006, the Canadian Federal Government announced a proposed Trust taxation pertaining to taxation of distributions paid by publicly traded income trusts and this was enacted by legislation in June, 2007. Previously, distributions paid to unitholders, other than returns of capital, were claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and is paid by the unitholders. The June, 2007 legislation results in a two-tiered tax structure whereby distributions commencing in 2011 would first be subject to a 31.5 percent tax at the Trust level and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation.

Prior to June, 2007 the Trust estimated the future income tax on certain temporary differences between amounts recorded on its balance sheet for book and tax purposes at a nil effective tax rate. The entire balance of the future income tax liability reported related to assets and liabilities and related tax amounts held through the Trust's 100 percent held subsidiaries. Under the legislation, the Trust now estimates the effective tax rate on post 2010 reversal of these temporary differences to be 31.5%. Temporary differences at the Trust level reversing before 2011 will still give rise to nil future income taxes.

Based on its assets and liabilities as at June 30, 2007, the Trust has estimated the amount

of its temporary differences which were previously not subject to tax and estimated the periods in which these differences will reverse. The Trust estimates that \$12,070,000 net taxable temporary differences will reverse after January 1, 2011, resulting in an additional \$3,801,000 future income tax liability. The taxable temporary differences relate principally to the excess of net book value of oil and gas properties over the remaining tax pools attributable thereto.

As the legislation gives rise to a change in the Trust's estimated future income tax liability in the period, the recognition of the additional liability is accounted for prospectively in the period and an additional \$3,801,000 of future income tax expense has been recorded for the period.

While the Trust believes it will be subject to additional tax under the new legislation, the estimated effective tax rate on temporary difference reversals after 2011 may change in future periods. As the legislation is new, future technical interpretations of the legislation could occur and could materially affect management's estimate of the future income tax liability.

The amount and timing of reversals of temporary differences will also depend on the Trust's future operating results, acquisitions and dispositions of assets and liabilities, and distribution policy. A significant change in any of the preceding assumptions could materially affect the Trust's estimate of the future income tax liability.

## 6. 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	41,000	705,000
Transfer of contributed surplus to unit capital	–	74,000
Balance, June 30, 2007	16,915,658	\$90,267,000

The number of trust units used to calculate diluted net earnings per unit for the period ended June 30, 2007 of 16,938,094 (2006 – 16,809,422) included the basic weighted average number of units outstanding of 16,905,494 (2006 – 16,703,957) plus 32,600 (2006 – 105,465) units related to the dilutive effect of unit options.

The deficit balance is composed of the following items:

	June 30, 2007	June 30, 2006
Accumulated earnings	<b>\$135,750,000</b>	\$105,494,000
Accumulated cash distributions	<b>(178,239,000)</b>	(131,559,000)
Deficit	<b>\$(42,489,000)</b>	\$(26,065,000)

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,692,000 (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 June 30, 2007 and December 31, 2006, and changes during the six month and twelve month periods ending on those dates is presented below:

	June 30, 2007		December 31, 2006	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	<b>721,500</b>	<b>\$26.55</b>	646,000	\$18.67
Options granted	<b>546,000</b>	<b>28.12</b>	447,000	29.18
Options exercised	<b>(41,000)</b>	<b>17.19</b>	(339,500)	15.20
Options cancelled	<b>(40,000)</b>	<b>28.21</b>	(32,000)	24.70
Outstanding at end of period	<b>1,186,500</b>	<b>\$27.54</b>	721,500	\$26.55
Options exercisable at end of period	<b>209,500</b>	<b>\$23.73</b>	212,500	\$22.62

The following table summarizes information about unit options outstanding at June 30, 2007:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number Outstanding At 6/30/07	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 6/30/07	Weighted-Average Exercise Price
\$22.45-\$23.35	237,500	1.7 years	\$23.32	194,500	\$23.35
\$24.20-\$25.00	24,000	2.6 years	24.34	–	–
\$26.60	5,000	2.6 years	26.60	–	–
\$28.30-\$28.75	880,000	2.4 years	28.49	15,000	28.72
\$32.00-\$33.75	40,000	2.5 years	33.55	–	–
\$22.45-\$33.75	1,186,500	2.3 years	\$27.54	209,500	\$23.73

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

## 7. ACCUMULATED OTHER COMPREHENSIVE INCOME

Six months ended June 30, 2007

	Opening	Other	Ending
	Comprehensive Income		
Unrealized gains and losses on available-for sale financial assets	\$1,566,000	\$ 628,000	\$2,194,000
Unrealized gains and losses on derivatives designated as cash flow hedges	814,000	(311,000)	503,000
	\$2,380,000	\$ (317,000)	\$2,697,000

## 8. RELATED PARTY TRANSACTIONS

The Trust received a management fee from Comaplex of \$150,000 (2006 - \$150,000) for management services, accounting services and office administration. This cost has been included as a recovery of general and administrative expenses. The above charge represents the fair value of the services rendered. At June 30, 2007 the Trust had an accounts receivable from Comaplex of \$60,000 (December 31, 2006 - \$38,000).

The Trust received a management fee from Pine Cliff Energy Ltd. (Pine Cliff) of \$108,000 (2006 - \$108,000) for management services, accounting services and office administration. This fee has been included as a recovery in general and administrative expenses. As at June 30, 2007 the Trust had no amounts for accounts receivable from or accounts payable to Pine Cliff. The above charge represents the fair value of the services rendered.

## 9. 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.)
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of \$75.00 and ceiling of \$93.00 per barrel
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of \$70.00 and ceiling of \$80.06 per barrel
January 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 October 31, 2007	Natural Gas	1,000 GJ's	AECO	Floor of \$6.50 and ceiling of \$9.20 per GJ
November 1, 2007 to March 31, 2008	Natural Gas	2,000 GJ's	AECO	Floor of \$6.50 and ceiling of \$10.37 per GJ

#### 10. SUBSEQUENT EVENT – DISTRIBUTION

Subsequent to June 30, 2007, the Trust entered into the following commodity hedging contract for a portion of its 2008 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
July 1, 2008 to December 31, 2008	Crude Oil	500 barrels	WTI	Floor of \$73.00 and ceiling of \$80.68 per barrel

#### 11. SUBSEQUENT EVENT – DISTRIBUTIONS

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



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