CARBON ENERGY CORP
Form 10-Q/A
September 15, 2003

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q/A

Amendment No. 1

ý **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2003

Or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to
Commission File Number: 1-15639

CARBON ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Colorado (State or other jurisdiction of incorporation or organization)	**84-1515097** (I.R.S. Employer Identification No.)
1700 Broadway, Suite 1150, Denver, CO (Address of principal executive offices)	**80290** (Zip Code)

(303) 863-1555
(Registrant's telephone number, including area code)
Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act) Yes o No ý

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 25, 2003
Common stock, no par value	6,272,544 shares

CARBON ENERGY CORPORATION
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PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

CARBON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
(in thousands)
(unaudited)

	June 30, 2003	December 31, 2002
ASSETS		
Current assets:		
Cash	$ 792	$
Accounts receivable, trade	4,304	3,240
Prepaid expenses and other	636	918
Total current assets	5,732	4,158

	June 30, 2003	December 31, 2002
Property and equipment, at cost:		
Oil and gas properties, using the full cost method of accounting:		
Unproved properties	8,893	7,080
Proved properties	73,780	71,223
Furniture and equipment	943	894
	83,616	79,197
Less accumulated depreciation, depletion and amortization	(34,144)	(31,503)
Property and equipment, net	49,472	47,694
Deposits and other long-term assets	465	452
Total assets	$ 55,669	$ 52,304

The accompanying notes are an integral part of these consolidated financial statements.

CARBON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
(in thousands)
(unaudited)

	June 30, 2003	December 31, 2002
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 5,433	$ 4,914
Accrued production taxes payable	370	337
Income taxes payable	681	
Undistributed revenue and other	1,871	1,462
Current derivative liability	1,414	1,116
Total current liabilities	9,769	7,829
Long-term debt	16,343	22,709
Other long-term liabilities	3,130	37
Deferred income taxes	4,311	3,093
Minority interest		28
Stockholders' equity:		
Preferred stock, no par value:		
10,000,000 shares authorized, none outstanding		
Common stock, no par value:		
20,000,000 shares authorized, 6,247,619 and 6,116,295 shares issued and outstanding at June 30, 2003 and December 31, 2002, respectively	32,270	31,987
Accumulated deficit	(10,574)	(12,017)
Accumulated other comprehensive income (loss)	420	(1,362)

	June 30, 2003		December 31, 2002
Total stockholders' equity		22,116		18,608
Total liabilities and stockholders' equity	$	55,669	$	52,304

The accompanying notes are an integral part of these consolidated financial statements.

CARBON ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands, except per share data)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
Revenues:				
Oil and gas sales	$ 5,323	$ 4,427	$ 12,277	$ 8,336
Other, net	(24)	101	(216)	179
	5,299	4,528	12,061	8,515
Expenses:				
Oil and gas production costs	1,857	1,617	3,604	3,163
Depreciation, depletion and amortization	1,204	1,697	2,655	3,437
Full cost ceiling impairment		13,218		13,218
General and administrative, net	1,471	1,161	2,984	2,490
Interest and other, net	181	259	520	452
Total operating expenses	4,713	17,952	9,763	22,760
Income (loss) before income taxes	586	(13,424)	2,298	(14,245)
Income tax provision:				
Current	384	33	841	60
Deferred	255	632	351	316
Total taxes	639	665	1,192	376
Income (loss) before cumulative effect of change in accounting principle	(53)	(14,089)	1,106	(14,621)
Cumulative effect of change in accounting principle, net of tax			336	
Net income (loss)	$ (53)	$ (14,089)	$ 1,442	$ (14,621)
Average number of common shares outstanding:				
Basic	6,149	6,097	6,134	6,091
Diluted	6,149	6,097	6,431	6,091
Earnings (loss) per share basic:				

	Three Months Ended June 30,		Six Months Ended June 30,	
Income (loss) before cumulative effect of change in accounting principle	$ (0.01)	$ (2.31)	$ 0.18	$ (2.40)
Cumulative effect of change in accounting principle, net of tax			0.06	
	$ (0.01)	$ (2.31)	$ 0.24	$ (2.40)
Earnings (loss) per share diluted:				
Income (loss) before cumulative effect of change in accounting principle	$ (0.01)	$ (2.31)	$ 0.17	$ (2.40)
Cumulative effect of change in accounting principle, net of tax			0.05	
	$ (0.01)	$ (2.31)	$ 0.22	$ (2.40)

The accompanying notes are an integral part of these consolidated financial statements.

CARBON ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(unaudited)

	For the Six Months Ended June 30,	
	2003	**2002**
Cash flows from operating activities:		
Net income (loss)	$ 1,442	$ (14,621)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	2,655	3,437
Full cost ceiling impairment		13,218
Unrealized (gain)/loss on derivative contracts	198	(122)
Deferred income tax	351	316
Vesting of restricted stock grants and other	79	76
Cumulative effect of change in accounting principle	(336)	
Changes in operating assets and liabilities:		
Decrease (increase) in:		
Accounts receivable	(624)	78
Prepaid expenses and other assets	228	(77)
Increase (decrease) in:		
Accounts payable and accrued expenses	(91)	(2,871)
Undistributed revenue	243	55
Net cash provided by (used in) operating activities	4,145	(511)
Cash flows from investing activities:		
Capital expenditures for oil and gas properties	(10,084)	(4,747)
Proceeds from property sales	14,537	2
Acquisition of minority interest in Carbon Energy Canada	(56)	(6)

	For the Six Months Ended June 30,	
Capital expenditures for support equipment	(39)	
Net cash provided by (used in) investing activities	4,358	(4,751)
Cash flows from financing activities:		
Proceeds from notes payable	35,918	14,495
Principal payments on notes payable	(43,730)	(9,300)
Proceeds from issuance of common stock	447	57
Net cash provided by (used in) financing activities	(7,365)	5,252
Effect of exchange rate changes on cash	(346)	10
Net increase in cash	792	
Cash, beginning of period		
Cash, end of period	$ 792	$
Supplemental cash flow information:		
Cash paid for interest	$ 537	$ 444
Cash paid for taxes	17	1,308

The accompanying notes are an integral part of these consolidated financial statements.

CARBON ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

1. Nature of Operations

Nature of Operations Carbon Energy Corporation (the Company or Carbon) is an independent oil and gas company engaged in the exploration, development and production of natural gas and crude oil in the United States and Canada. The Company's areas of operations in the United States are the Piceance Basin in Colorado, the Uintah Basin in Utah and Montana. The Company's areas of operations in Canada are central and northwest Alberta and southeast Saskatchewan.

The Company's business is comprised of the assets and properties of Carbon Energy Corporation (USA) (Carbon USA), which conducts the Company's operations in the United States, and the assets and properties of Carbon Energy Canada Corporation (Carbon Canada), which conducts the Company's operations in Canada. Effective July 11, 2002, Carbon changed the name of its United States subsidiary from Bonneville Fuels Corporation (Bonneville Fuels) to Carbon Energy Corporation (USA). Effective March 1, 2003, Carbon changed the name of its Canadian subsidiary from CEC Resources Ltd. (CEC Resources) to Carbon Energy Canada Corporation. As the parent company, Carbon provides management services to Carbon USA and Carbon Canada. Collectively, Carbon, Carbon Canada, Carbon USA and their subsidiaries are referred to as the Company.

Carbon was incorporated in September 1999 under the laws of the State of Colorado to facilitate the acquisition of Carbon USA and subsidiaries. The acquisition of Carbon USA closed on October 29, 1999 and was accounted for as a purchase. In February 2000, Carbon completed an offer to exchange common shares of Carbon for shares of Carbon Canada, an Alberta, Canada company. Over 97% of the shareholders of Carbon Canada accepted the offer for exchange. This acquisition closed on February 17, 2000 and was also accounted for as a purchase. In November 2000, Carbon Canada initiated an offer to purchase additional shares of Carbon Canada stock that were not owned by Carbon. The offer was completed in February 2001 with the acquisition of approximately 34,000 of the 39,000 shares of Carbon Canada stock that were not owned by Carbon. In October 2002, Carbon Canada amended its articles to consolidate its issued and outstanding common shares on a one-for-2,500 basis. In November 2002, Carbon Canada initiated the exchange of common shares for post-consolidation shares or a cash payment in lieu of fractional post-consolidated shares. The exchange was completed in January 2003, after which Carbon owned 100% of the stock of Carbon Canada.

On March 31, 2003, Carbon announced that it had entered into an Agreement and Plan of Reorganization (the Merger Agreement) with Evergreen Resources, Inc. (Evergreen). Under the Merger Agreement, Carbon will merge with a subsidiary of Evergreen, and Carbon stockholders will receive .275 shares of Evergreen common stock for each outstanding share of Carbon common stock (and cash in lieu of any fractional shares). This ratio is prior to the two-for-one split of Evergreen common stock for shareholders of record on August 29, 2003 announced by Evergreen on July 31, 2003. As a result of the merger, Carbon will become a wholly owned subsidiary of Evergreen. The merger is intended to be a tax-free, stock-for-stock transaction. At the time of execution of the agreement, each of Yorktown Energy Partners III, L.P. and Patrick R. McDonald, President and Chief Executive Officer of Carbon, who own approximately 71.7% and 4.1%, respectively, of Carbon's outstanding common stock, had executed an agreement with Evergreen obligating each of them to vote all shares over which they have voting control in favor of the merger.

Completion of the merger, which is subject to customary conditions, including approval by the stockholders of Carbon, is expected to occur in the third quarter of 2003. The Merger Agreement contains a $2.5 million termination fee payable by Carbon if the Merger Agreement is terminated under certain circumstances.

Basis of Presentation The unaudited financial statements presented herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC). The statements do not include all information and note disclosures required by accounting principles generally accepted in the United States for complete financial statements. It is suggested that the accompanying consolidated financial statements of the Company be read in conjunction with the consolidated financial statements and notes thereto included in the Company's Annual Report on Forms 10-K and 10-K/A for the year ended December 31, 2002, as filed with the SEC. The statements reflect all adjustments that, in the opinion of management, are necessary to fairly present the Company's financial position at June 30, 2003 and the results of its operations and its cash flows for the periods presented.

All amounts are presented in U.S. dollars.

2. Significant Accounting Policies

Principles of Consolidation The consolidated financial statements include the accounts of Carbon and its subsidiaries, all of which are wholly owned. All significant intercompany transactions and balances have been eliminated.

Cash Equivalents The Company considers all highly liquid instruments with original maturities of three months or less when purchased to be cash equivalents.

Property and Equipment The Company follows the full cost method of accounting for its oil and gas properties, whereby all costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and direct overhead related to exploration and development activities) are capitalized.

Capitalized costs are accumulated for the United States and Canada as separate cost centers and are depleted using the units of production method based on proved reserves of oil and gas. For purposes of the depletion calculation, oil and gas reserves are converted to an equivalent unit of measure where six thousand cubic feet of gas is equal to one barrel of oil. For periods prior to January 1, 2003, the estimated future cost of site restoration, dismantlement and abandonment activities was provided for as a component of depletion (see discussion of asset retirement costs and obligations below). Investments in unproved properties are recorded at the lower of cost or fair market value and are not depleted pending the determination of the existence of proved reserves.

Pursuant to full cost accounting rules, capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of the present value of future net revenues from estimated production of proved oil and gas reserves using a 10% discount factor and unescalated oil and gas prices and costs as of the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair market value of unproved properties included in the costs being amortized, if any; less related income tax effects. At June 30, 2003, the costs reflected in the accompanying financial statements did not exceed the ceiling limitation in either the United States or Canada. Should natural gas and oil prices decline in the future, it is possible that impairments of the Company's oil and gas properties could occur.

Proceeds from disposal of interests in oil and gas properties are accounted for as adjustments of capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the rate of depletion.

Buildings, transportation and other equipment are depreciated on the straight-line method with lives ranging from three to seven years.

Asset Retirement Costs and Obligations The Company adopted the provisions of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) on January 1, 2003. This statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The asset retirement obligation is allocated to operating expense using a systematic and rational method.

Upon adoption of the statement, the Company recorded an asset retirement obligation of approximately $3.0 million, an addition to oil and gas properties of approximately $3.5 million and a credit of approximately $336,000 (net of tax) for the cumulative effect of change in accounting principle. At June 30, 2003, the asset retirement obligation is recorded in other long-term liabilities. Below is a reconciliation of the beginning and ending aggregate carrying amount of the Company's asset retirement obligations as of June 30, 2003:

	Six Months Ended June 30, 2003 (in thousands)
Beginning of the period	$
Initial adoption entry	2,999
Liabilities incurred in the current period	283
Liabilities disposed of in the current period	(399)
Accretion expense	113
Impact of foreign currency exchange rate change	134
End of the period	$ 3,130

The following table summarizes the pro forma net income and earnings per share for the six months ended June 30, 2002 and for the years ended December 31, 2002, 2001 and 2000 had the change in accounting been implemented on January 1 of the respective years:

	Six Months Ended June 30, 2002	Year Ended December 31, 2002	2001	2000
	(in thousands, except per share data)			
Net income (loss)				
As reported	$ (14,621)	$ (14,555)	$ 1,573	$ 1,456
Pro forma	(14,556)	(14,425)	1,690	1,570
Basic earnings (loss) per common share:				
As reported	$ (2.40)	$ (2.39)	$ 0.26	$ 0.25
Pro forma	(2.39)	(2.35)	0.28	0.27
Diluted earnings (loss) per common share:				
As reported	$ (2.40)	$ (2.39)	$ 0.25	$ 0.25
Pro forma	(2.39)	(2.35)	0.27	0.27

The difference in the as reported and pro forma net income include the effects of the accretion of the asset retirement obligation and a decrease in depletion expense as a result of adopting SFAS No. 143. In addition, had the Company adopted the provisions of SFAS No. 143 prior to January 1, 2003, the amount of the asset retirement obligation on a pro forma basis would have been as follows:

Adoption Date	Pro Forma Asset Retirement Obligation (in thousands)
January 1, 2000	$ 1,570
December 31, 2000	2,250
December 31, 2001	2,672
June 30, 2002	2,826
December 31, 2002	2,999

Undistributed Revenue Represents revenue due to third party owners of jointly owned oil and gas properties.

Revenue Recognition The Company follows the sales method of accounting for natural gas revenues. Under this method, revenues are recognized based on the actual volume of gas sold to purchasers. To the extent the volumes of gas sold are more (over produced) or less (under produced) than the volumes to which the Company is entitled based on its interests in its properties, a gas imbalance may be created. If the estimated remaining reserves of a property are insufficient to enable the underproduced owner to recoup its share of production, a liability is created.

Transportation Costs Gathering and transportation costs incurred by the Company are included as components of oil and gas production costs in the accompanying statements of operations. Under the Company's sales contracts for the six months ended June 30, 2003 and 2002, purchasers assumed all obligations under transportation agreements. As a result, the Company did not incur any transportation costs during this time and reported its gas revenues net of transportation costs incurred by purchasers of its natural gas.

Income Taxes The Company accounts for income taxes using the liability method which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements or tax returns. Under this method, deferred tax assets and liabilities are determined based on the difference between the book and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

Foreign Currency Translation Foreign currency transactions and financial statements are translated in accordance with SFAS No. 52, "Foreign Currency Translation." The Company uses the U.S. dollar as the functional currency for its U.S. operations and the Canadian dollar as the functional currency for its Canadian operations. Assets and liabilities related to the Company's Canadian operations are generally translated at the current exchange rate in effect as of the date of the balance sheet. Translation adjustments are reported as a component of stockholders' equity. Income statement accounts are translated at the average exchange rates during the reporting period. As a result of the change in the value of the Canadian dollar relative to the U.S. dollar, the Company reported non-cash currency translation gains of $1.8 million and $499,000 for the six months ended June 30, 2003 and 2002, respectively.

Comprehensive Income The Company follows the provisions of SFAS No. 130, "Reporting Comprehensive Income." Comprehensive income includes net income and certain items recorded directly to stockholders' equity and are classified as other comprehensive income.

Stock-Based Compensation The Company applies APB Opinion (APB) No. 25 "Accounting for Stock Issued to Employees" and related interpretations in accounting for its employee stock options. Under APB No. 25, compensation expense is recognized for the difference between the option price and market value on the measurement date. No compensation expense was recognized for the six months ended June 30, 2003 and 2002 as the exercise price of the stock options granted under the plan equaled the market price of the underlying stock on the date of grant.

The Company applies SFAS No. 123 "Accounting for Stock-Based Compensation," and related literature in accounting for stock-based awards granted to non-employees other than directors. Under SFAS No. 123, stock-based awards granted to non-employees other than directors are recorded at fair value and recognized in the period(s) in which goods and/or services are received from the non-employee. To date, the Company has never granted stock-based awards to non-employees other than directors.

If compensation costs for this plan had been determined consistent with SFAS No. 123, the Company's net income (loss) and earnings (loss) per share would have been as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	(in thousands except per share data)		(in thousands except per share data)	
Net income (loss):				
As reported	$ (53)	$ (14,089)	$ 1,442	$ (14,621)
Pro forma	(105)	(14,131)	1,339	(14,704)
Basic earnings (loss) per common share:				
As reported	$ (0.01)	$ (2.31)	$ 0.24	$ (2.40)
Pro forma	(0.02)	(2.32)	0.22	(2.41)
Diluted earnings (loss) per common share:				
As reported	$ (0.01)	$ (2.31)	$ 0.22	$ (2.40)

	Three Months Ended June 30,		Six Months Ended June 30,	
Pro forma	(0.02)	(2.32)	0.21	(2.41)

Earnings (Loss) Per Share The Company uses the weighted average number of shares outstanding to calculate earnings per share data. When dilutive, options are included as share equivalents using the treasury stock method and are included in the calculation of diluted per share data. Due to the Company's net loss for the three month periods ended June 30, 2003 and 2002 and the six month period ended June 30, 2002, basic and diluted earnings per share are the same, as all potentially dilutive securities would be anti-dilutive.

Accounting Estimates The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in these financial statements and the accompanying notes. The actual results could differ from those estimates.

Recent Accounting Pronouncements In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated With Exit or Disposal Activities," which provides guidance for financial accounting and reporting of costs associated with exit or disposal activities. This statement requires the recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan as previously required under EITF No. 94-3. The adoption of SFAS No. 146 on January 1, 2003, had no impact on the Company's financial position or results of operations.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities under FASB Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The Company does not expect the adoption of this statement to have a material effect on its financial statements.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity." SFAS No. 150 establishes standards for how an issuer measures certain financial instruments with characteristics of both liabilities and equity and requires that an issuer classify a financial instrument within its scope as a liability (or asset in some circumstances). SFAS No. 150 was effective for financial instruments entered into or modified after May 31, 2003 and otherwise was effective and adopted by the Company on July 1, 2003. As the Company has no such instruments, the Company's adoption of this statement did not have an impact on its financial condition or results of operation.

In June 2001, the FASB issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 141 addresses accounting and reporting for business combinations and is effective for all business combinations initiated after June 30, 2001. SFAS No. 142 addresses the accounting and reporting for acquired goodwill and other intangible assets. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill is required to be reviewed at least annually for impairment. The new standard also requires that, at a minimum, all intangible assets be aggregated and presented as a separate line item in the balance sheet. The adoption of SFAS No. 141 and SFAS No. 142 had no impact on the Company's financial position or results of operations.

A reporting issue has arisen regarding the application of certain provisions of SFAS No. 141 and SFAS No. 142 to companies in the extractive industries, including oil and gas companies. The issue is whether SFAS No. 142 requires registrants to classify the costs of mineral rights associated with extracting oil and gas as intangible assets in the balance sheet, apart from other capitalized oil and gas property costs, and provide specific footnote disclosures. Historically, the Company has included the costs of mineral rights associated with extracting oil and gas as a component of oil and gas properties. If it is ultimately determined that SFAS No. 142 requires oil and gas companies to classify costs of mineral rights associated with extracting oil and gas as a separate intangible assets line item on the balance sheet, the Company would be required to reclassify approximately $6.9 million and $2.5 million at June 30, 2003 and December 31, 2002, respectively, out of oil and gas properties and into a separate intangible assets line item. The Company's cash flows and results of operations would not be affected since such intangible assets would continue to be depleted and assessed for impairment in accordance with full cost accounting rules. Further, the Company does not believe the classification of the costs of mineral rights associated with extracting oil and gas as intangible assets would have any impact on the Company's compliance with covenants under its debt agreements.

3. Acquisition and Disposition of Assets

Disposition of Oil and Gas Assets In July 2002, the Company sold certain overriding royalty interests in the Piceance and Permian Basins, receiving net proceeds of approximately $700,000. Proceeds from the sale were credited directly to the full cost pool and no gain or loss was recognized. The proceeds were used to repay amounts outstanding under the Company's credit facilities.

In September 2002, the Company sold its entire working interests and related leasehold rights in Kansas, receiving net proceeds of approximately $2.1 million. Proceeds from the sale were credited directly to the full cost pool and no gain or loss was recognized. The proceeds were used to repay amounts outstanding under the Company's credit facilities.

On March 24, 2003, Carbon USA closed on the sale of its interests in oil and gas properties located primarily in the Permian Basin of southeast New Mexico. Net proceeds from the sale, after normal closing adjustments, were $14.4 million. Proceeds from the sale were credited directly to the full cost pool and no gain or loss was recognized. A portion of the proceeds from the sale were used to repay borrowings under the Company's U.S. credit facility.

4. Long-term Debt

U.S. Facility On December 31, 2002, the Company obtained a credit facility from the Bank of Oklahoma, National Association (Bank of Oklahoma). Borrowings under the Bank of Oklahoma credit facility were used to repay outstanding borrowings under the Company's previous credit facility with Wells Fargo Bank West National Association. The facility has a borrowing base of $14.0 million and at June 30, 2003 outstanding borrowings under the credit facility were $4.7 million.

The facility has a maturity date of October 2005 with no principal payments required until maturity. The interest rates on amounts borrowed under the facility vary depending upon outstanding borrowings as a percentage of the borrowing base. The Company's weighted average interest rate was 3.2% at June 30, 2003.

The facility is secured by certain U.S. oil and gas properties of the Company and contains various convenants which prohibit or limit the Company's ability to pay dividends, purchase treasury shares, incur indebtedness, sell properties or merge with another entity. The Company is also required to maintain certain financial ratios. The Company was in compliance with all debt covenants at June 30, 2003. The Company has been informed by Evergreen that the credit facility with the Bank of Oklahoma is expected to be repaid in full at the time of the proposed merger of the Company with Evergreen.

Canadian Credit Facility Carbon Canada's credit facility is an oil and gas reserve based line-of-credit with Canadian Imperial Bank of Commerce (CIBC). In May 2003, the Company secured an increase in the borrowing base of the facility with CIBC to approximately $16.2 million from approximately $11.8 million. At June 30, 2003 outstanding borrowings were $11.6 million. The Canadian facility is secured by the Canadian oil and gas properties of the Company. The revolving phase of the Canadian facility expires on March 31, 2004. If the revolving commitment is not renewed, the loan will be converted into a term loan and will be reduced by consecutive monthly payments over a period not to exceed 24 months. Subject to possible changes in the borrowing base, CIBC has agreed that it will not require the Company to make principal payments under the term loan section of the facility until July 2004 at the earliest. As such, no amounts under the CIBC facility have been classified as current at June 30, 2003. The Canadian facility bears interest at a rate equal to banker's acceptance rates plus 1.25% or at the CIBC Prime rate plus .5%. The Company's weighted average interest rate was 5.5% at June 30, 2003.

The Canadian facility contains various covenants that limit the Company's ability to pay dividends, purchase treasury shares, incur indebtedness, sell properties, or merge with another entity. The Company was in compliance with all debt covenants at June 30, 2003.

The agreement with CIBC also provides for $5.0 million of credit which can be utilized for financial derivative instruments used to hedge a portion of the Company's oil and gas production, currency exchange contracts and fixed price gas sales transactions with CIBC. The Company currently utilizes the swap facility to hedge a portion of its Canadian production as described in Note 5.

The Company has obtained the consent of CIBC to the merger of the Company with Evergreen.

5. Derivative Instruments

Interest Rate Swap Agreements During 2002, the Company entered into interest rate swap agreements that effectively converted a portion of its variable rate borrowings in the United States to fixed rate debt for periods of up to two years, reducing the impact of interest rate increases or decreases on future income. Quarterly settlements from interest rate swaps that qualify for hedge accounting treatment are recognized as an adjustment to interest expense. Changes in the fair value of interest rate swaps that do not qualify for hedge accounting treatment are recognized in the current period as a component of other revenues, net. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flow. The table below sets forth the Company's interest rate derivative contracts in place at June 30, 2003:

Notional Amount (in thousands)	Contract Expiration Date	Effective Fixed Rate	Asset/ (Liability) (in thousands)
$ 2,000	October 2003	3.77%	$ (26)
800	October 2003	3.82%	(11)
1,000	March 2004	4.15%	(23)
2,500	April 2004	4.24%	(78)

Notional Amount	Contract Expiration Date	Effective Fixed Rate	Asset/ (Liability)
			$ (138)

During the first six months of 2003, net hedging losses of $68,000 ($42,000 after tax) relating to interest rate derivative contracts designated as hedges were transferred from accumulated other comprehensive income to earnings. In March 2003, Carbon USA closed on the sale of its interest in oil and gas properties located primarily in the Permian Basin of southeast New Mexico. Proceeds from the sale were used to repay borrowings under the Company's U.S. credit facility with Bank of Oklahoma. As a result of this use of proceeds, the Company no longer had variable rate borrowings underlying certain of its interest rate swap agreements. As a result, the Company discontinued hedge accounting for these interest rate swaps and during the first six months of 2003 recognized expenses of $182,000 ($113,000 after tax). As of June 30, 2003, the Company had net unrealized interest derivative losses of $138,000 ($86,000 after tax) that have been recorded to income, related to the change in the fair value of these interest rate swap agreements.

Commodity Derivative Instruments and Hedging Activities The Company may use certain financial instruments including swaps, collars, futures and other contracts in an attempt to reduce exposure to market fluctuations in the price of oil and natural gas.

Pursuant to Company guidelines, the Company is to engage in these activities only as a hedging mechanism and may not enter into speculative transactions. Gains or losses from financial instruments that qualify for hedge accounting treatment are recognized as an adjustment to sales revenue in the period in which the financial instrument matures. Changes in the fair value of financial instruments that do not qualify for hedge accounting treatment are recognized during the current period as a component of other revenues, net. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flows. The following table sets forth the hedge gains (losses) realized by the Company for the three and six-month periods ended June 30, 2003 and 2002 (in thousands):

	Three Months Ended June 30, 2003		Three Months Ended June 30, 2002		Six Months Ended June 30, 2003		Six Months Ended June 30, 2002	
	United States	Canada	United States	Canada	United States	Canada	United States	Canada
Oil	$	$ (1)	$ (16)	$	$ (157)	$ (65)	$ (16)	$ 11
Natural gas	(454)	(73)	13	(79)	(670)	(284)	64	16

The table below sets forth the Company's derivative financial instrument positions relating to its natural gas and oil production at June 30, 2003:

Swaps:

Carbon USA				Carbon Canada			
Time Period	Bbl/ MMBtu	Weighted Average Fixed Price Bbl/ MMBtu	Derivative Asset/ (Liability)	Time Period	Bbl/ MMBtu	Weighted Average Fixed Price Bbl/ MMBtu	Derivative Asset/ (Liability)
			(in thousands)				(in thousands)
Gas				**Gas**			
07/01/03-12/31/03	675,000	$ 3.07	$ (1,107)	07/01/03-12/31/03	87,000	$ 3.42	$ (122)
Oil				**Oil**			
07/01/03-12/31/03	18,400	$ 25.63	$ (61)	07/01/03-12/31/03	18,400	$ 29.68	$ 14

The Company periodically enters into long-term physical sales contracts for a portion of its natural gas and oil production. The table below sets forth physical fixed price and costless collar sales contracts at June 30, 2003:

Fixed price:

Carbon Canada	
Time Period	MMBtu

Costless collars:

Carbon Canada	
Time Period	MMBtu

Carbon Canada			Carbon Canada			
		Weighted Average Fixed Price MMBtu			Weighted Average Floor Price MMBtu	Weighted Average Ceiling Price MMBtu
Gas			**Gas**			
07/01/03-12/31/03	494,000	$ 4.05	07/01/03-12/31/03	203,000	$ 4.28	$ 5.62
			01/01/04-04/30/04	115,000	4.28	6.26

During the first six months of 2003, net hedging losses of $1.2 million ($720,000 after tax) relating to commodity derivative contracts designated as hedges were transferred from accumulated other comprehensive income to earnings. The fair value of outstanding commodity derivative contracts designated as hedges decreased by $1.5 million ($947,000 after tax). In March 2003, Carbon USA closed on the sale of its interest in oil and gas properties located primarily in the Permian Basin of southeast New Mexico. At the time of the sale, the Company had an oil commodity swap that was utilized to hedge the Company's Permian Basin oil production. As a result of the sale, the Company no longer had Permian Basin oil production underlying this commodity derivative contract. Consequently, the Company discontinued hedge accounting for this contract during the first six months of 2003 and recognized expenses of $90,000 ($56,000 after tax) of which $61,000 is unrealized at June 30, 2003, related to the change in the fair value of this contract. Other than the above mentioned commodity derivative contract, oil and natural gas prices reflective of the Company's hedge contracts were correlative with the published indices used to sell the Company's production. As a result, except for the above mentioned commodity derivative contract, no ineffectiveness was recognized related to the Company's hedge contracts during the six months ended June 30, 2003. As of June 30, 2003, the Company had net unrealized commodity derivative losses of $1.3 million ($793,000 after tax) including $61,000 in losses that have been recorded to income. The Company expects to reclassify the remainder of these net unrealized losses to earnings during the next twelve months.

6. Business and Geographical Segments

Segment information has been prepared in accordance with SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." For the three and six month periods ended June 30, 2003 and 2002, Carbon had two reportable segments: Carbon USA and Carbon Canada, representing oil and gas operations in the United States and Canada, respectively. The Company evaluates performance of its reportable segments based on profit or loss from oil and gas operations before income taxes. Because Carbon USA and Carbon Canada are managed separately based on their geographic locations, the Company identified them as reportable segments under SFAS No. 131. The segment data presented below was prepared on the same basis as Carbon's consolidated financial statements (in thousands).

	Three Months Ended June 30, 2003			Six Months Ended June 30, 2003		
	United States	Canada	Total	United States	Canada	Total
Revenues:						
Oil and gas sales	$ 1,762	$ 3,561	$ 5,323	$ 5,051	$ 7,226	$ 12,277
Other, net	(24)		(24)	(216)		(216)
	1,738	3,561	5,299	4,835	7,226	12,061
Expenses:						
Oil and gas production costs	1,213	644	1,857	2,567	1,037	3,604
Depreciation, depletion and amortization	392	812	1,204	1,147	1,508	2,655
General and administrative, net	867	604	1,471	1,844	1,140	2,984
Interest and other, net	54	127	181	290	230	520
Total operating expenses	2,526	2,187	4,713	5,848	3,915	9,763
Income (loss) before income taxes and cumulative effect of accounting change	(788)	1,374	586	(1,013)	3,311	2,298
Income tax provision (benefit)		639	639	(90)	1,282	1,192
Net income (loss) before cumulative effect of accounting change	$ (788)	$ 735	$ (53)	$ (923)	$ 2,029	$ 1,106

	Three Months Ended June 30, 2003			Six Months Ended June 30, 2003		
Total assets	$ 18,921	$ 36,748	$ 55,669	$ 18,921	$ 36,748	$ 55,669
Capital expenditures	$ 1,010	$ 2,010	$ 3,020	$ 2,360	$ 7,724	$ 10,084

	Three Months Ended June 30, 2002			Six Months Ended June 30, 2002		
	United States	Canada	Total	United States	Canada	Total
Revenues:						
Oil and gas sales	$ 2,579	$ 1,848	$ 4,427	$ 4,839	$ 3,497	$ 8,336
Other, net	101		101	179		179
	2,680	1,848	4,528	5,018	3,497	8,515
Expenses:						
Oil and gas production costs	1,219	398	1,617	2,349	814	3,163
Depreciation, depletion and amortization	1,034	663	1,697	2,116	1,321	3,437
Full cost ceiling impairment	12,003	1,215	13,218	12,003	1,215	13,218
General and administrative, net	746	415	1,161	1,624	866	2,490
Interest and other, net	207	52	259	370	82	452
Total operating expenses	15,209	2,743	17,952	18,462	4,298	22,760
Loss before income taxes and cumulative effect of accounting change	(12,529)	(895)	(13,424)	(13,444)	(801)	(14,245)
Income tax provision (benefit)	1,089	(424)	665	746	(370)	376
Loss before cumulative effect of accounting change	$ (13,618)	$ (471)	$ (14,089)	$ (14,190)	$ (431)	$ (14,621)
Total assets	$ 29,722	$ 21,707	$ 51,429	$ 29,722	$ 21,707	$ 51,429
Capital expenditures	$ 522	$ 1,790	$ 2,312	$ 1,289	$ 3,458	$ 4,747

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

On March 31, 2003, Carbon announced that it had entered into an Agreement and Plan of Reorganization (the Merger Agreement) with Evergreen Resources, Inc. (Evergreen). Under the Merger Agreement, Carbon will merge with a subsidiary of Evergreen, and Carbon stockholders will receive .275 shares of Evergreen common stock for each outstanding share of Carbon common stock (and cash in lieu of any fractional shares). This ratio is prior to the two-for-one split of Evergreen common stock for shareholders of record on August 29, 2003 announced by Evergreen on July 31, 2003. As a result of the merger, Carbon will become a wholly owned subsidiary of Evergreen. The merger is intended to be a tax-free, stock-for-stock transaction. At the time of execution of the agreement, each of Yorktown Energy Partners III, L.P. and Patrick R. McDonald, President and Chief Executive Officer of Carbon, who own approximately 71.7% and 4.1%, respectively, of Carbon's outstanding common stock, had executed an agreement with Evergreen obligating each of them to vote all shares over which they have voting control in favor of the merger.

Completion of the merger, which is subject to customary conditions, including approval by the stockholders of Carbon, is expected to occur in the third quarter of 2003. The Merger Agreement contains a $2.5 million termination fee payable by Carbon if the Merger Agreement is terminated under certain circumstances.

Statements contained in the following management discussion and analysis of financial conditions and results of operations that are not historical facts are forward-looking statements and are subject to completion of the proposed merger.

Critical Accounting Policies

The following summarizes several of our critical accounting policies. See a complete list of significant accounting policies in Note 2 to the Consolidated Financial Statements in this report.

Property and Equipment The Company follows the full cost method of accounting for its oil and gas properties. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and direct overhead related to exploration and development activities) are capitalized.

Capitalized costs are accumulated for the United States and Canada as separate cost centers and are depleted using the units of production method based on proved reserves of oil and gas. For purposes of the depletion calculation, oil and gas reserves are converted to an equivalent unit of measure where six thousand cubic feet of gas is equal to one barrel of oil. For periods prior to January 1, 2003, the estimated future cost of site restoration, dismantlement and abandonment activities was provided for as a component of depletion. Investments in unproved properties are recorded at the lower of cost or fair market value and are not depleted pending the determination of the existence of proved reserves.

Pursuant to full cost accounting rules, capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of the present value of future net revenues from estimated production of proved oil and gas reserves using a 10% discount factor and unescalated oil and gas prices and costs as of the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects.

Reserves There are many uncertainties inherent in estimating crude oil and natural gas reserve quantities, projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved reserves are the estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves expected to be recovered through existing equipment and operating methods.

Derivative Instruments and Hedging Activities Pursuant to Company guidelines, the Company utilizes derivative instruments only as a hedging mechanism and does not enter into speculative transactions. The Company has a Risk Management Committee to administer and approve all hedging transactions. Gains or losses from commodity derivative instruments that qualify for hedge accounting treatment are recognized as an adjustment to sales revenue in the period in which the derivative instrument matures. Gains or losses from financial instruments that do not qualify for hedge accounting treatment are recognized during the current period as a component of other revenues, net. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flows.

The estimation of fair values for the Company's hedging derivatives requires substantial judgement. The fair values of the Company's derivatives are estimated on a monthly basis using an option pricing model. The option pricing model uses various factors that include closing exchange prices, volatility and the time value of options. The estimated future prices are compared to the prices fixed by the hedge agreements and the resulting estimated future cash inflows (outflows) over the lives of the hedges are discounted. These pricing and discounting variables are sensitive to market volatility as well as to changes in future price forecasts, regional price differentials and interest rates.

Valuation of Deferred Tax Assets The Company uses the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between the financial statement carrying values and their respective income tax bases (temporary differences). Future income tax assets and liabilities are measured using the tax rates expected to be in effect when the temporary differences are likely to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in operations in the period in which the change is enacted. The amount of future income tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment.

Results of Operations

The following table and discussion present comparative revenue, production volumes, average sales prices, expenses and percentage change between periods for the three months ended June 30, 2003 and 2002 (second quarter) for the Company's United States and Canadian operations.

	United States Three Months Ended June 30,			Canada Three Months Ended June 30,		
	2003	**2002**	**Change**	**2003**	**2002**	**Change**
	(in thousands, except prices and per Mcfe information)			(in thousands, except prices and per Mcfe information)		
Revenues:						
Oil and gas revenues	$ 1,762	$ 2,579	-32%	$ 3,561	$ 1,848	93%
Other, net	(24)	101	-124%			n/a
Total revenues	$ 1,738	$ 2,680	-35%	$ 3,561	$ 1,848	93%
Daily production volumes:						
Natural gas (MMcf)	5.1	8.4	-39%	7.5	6.4	17%
Oil and liquids (Bbl)	98	242	-60%	166	139	19%
Equivalent production (MMcfe 6:1)	5.7	9.9	-42%	8.5	7.2	18%
Average price realized:						
Natural gas (Mcf)	$ 3.37	$ 2.70	25%	$ 4.66	$ 2.76	69%
Oil and liquids (Bbl)	20.85	23.17	-10%	24.14	20.04	20%
Direct lifting costs	$ 298	$ 373	-20%	$ 645	$ 382	69%
Average direct lifting costs/Mcfe	0.57	0.41	39%	0.83	0.58	43%
Other production costs	915	846	8%	(1)	16	-106%
General and administrative, net	867	746	16%	604	415	46%
Depreciation, depletion and amortization	392	1,034	-62%	812	663	22%
Full cost ceiling impairment		12,003	n/a		1,215	n/a
Interest and other expense, net	54	207	-74%	127	52	144%
Income tax provision (benefit)		1,089	n/a	639	(424)	251%

Revenues from oil, liquids and gas sales of Carbon USA for the second quarter of 2003 were $1.8 million, a 32% decrease from 2002. The decrease was due primarily to decreased oil, liquids and natural gas production in the second quarter of 2003 due to the disposition of the Company's Kansas assets in September 2002 and Permian Basin assets in March 2003, partially offset by increased natural gas prices.

Revenues from oil, liquids and gas sales of Carbon Canada for the second quarter of 2003 were $3.6 million, a 93% increase from 2002. The increase was due primarily to increased oil, liquids and natural gas prices and increased oil, liquids and natural gas production.

Average production in the United States for the second quarter of 2003 was 98 barrels of oil and liquids per day and 5.1 million cubic feet (MMcf) of gas per day, a decrease of 42% from the same period in 2002 on a Mcf equivalent (Mcfe) basis where one barrel of oil or liquids is equal to six Mcf of gas. The decrease in production was primarily due to the disposition of the Company's Kansas assets in September 2002 and Permian Basin assets in March 2003. Exclusive of these disposed assets, average production in the United States for the second quarter of 2003 increased 6% on a Mcfe basis compared to 2002. During the second quarter of 2003, Carbon USA participated in the drilling of one gross (1 net) gas well compared to one gross (.1 net) oil well during the second quarter of 2002.

Average production in Canada for the second quarter of 2003 was 166 barrels of oil and liquids per day and 7.5 MMcf of gas per day, an increase of 18% on a Mcfe basis from the same period in 2002. The increase was primarily due to successful drilling activities in the third and fourth quarters of 2002 and first and second quarters of 2003 in the Carbon and Rowley areas of central Alberta. During the second quarter of 2003, Carbon Canada participated in the drilling of six gross (1.9 net) gas wells compared to four gross (2.7 net) gas wells during the second quarter of 2002.

Average oil and liquids prices realized by Carbon USA decreased 10% from $23.17 per barrel for the second quarter of 2002 to $20.85 for 2003. The average oil and liquids price includes hedge losses of $16,000 or $.71 per barrel for the second quarter of 2002. There was no oil hedge activity for the second quarter of 2003. Average natural gas prices realized by Carbon USA increased 25% from $2.70 per Mcf for the second quarter of 2002 to $3.37 for 2003. The average natural gas price includes hedge losses of $454,000 or $.97 per Mcf for the second quarter of 2003 compared to hedge gains of $13,000 or $.02 per Mcf for 2002.

Average oil and liquids prices realized by Carbon Canada increased 20% from $20.04 per barrel for the second quarter of 2002 to $24.14 for 2003. The average oil and liquids price includes hedge losses of $1,000 or $.06 per barrel for the first quarter of 2003. There was no oil hedge activity for the second quarter of 2002. Average natural gas prices realized by Carbon Canada increased 69% from $2.76 per Mcf for the second quarter of 2002 to $4.66 for 2003. The average natural gas price includes hedge losses of $73,000 or $.11 per Mcf for the second quarter of 2003 compared to hedge losses of $79,000 or $.14 per Mcf for 2002.

Other losses in the United States for the second quarter of 2003 were $24,000 compared to revenues of $101,000 for 2002. The loss for the second quarter of 2003 was primarily due to losses of $55,000 on derivative instruments that did not qualify for hedge accounting treatment, partially offset by gathering revenues. Other revenues for the second quarter of 2002 consisted primarily of gains of $70,000 on derivative instruments that did not qualify for hedge accounting treatment and gathering revenues.

Direct lifting costs incurred by Carbon USA were $298,000 or $.57 per Mcfe for the second quarter of 2003 compared to $373,000 or $.41 per Mcfe for 2002. The higher per Mcfe expense in the second quarter of 2003 compared to 2002 was primarily due to workover expenses in the Piceance Basin and charges for prior period adjustments in the Permian Basin.

Other production costs incurred by Carbon USA, consisting primarily of severance taxes, gathering and processing fees and production overhead, were $915,000 for the second quarter of 2003 compared to $846,000 for 2002. The increase was primarily due to increased gathering and processing fees due to increased natural gas prices, partially offset by decreased production taxes and overhead expenses as a result of the disposition of the Company's Kansas assets in September 2002 and Permian Basin assets in March 2003.

Direct lifting costs incurred by Carbon Canada were $645,000 or $.83 per Mcfe for the second quarter of 2003 compared to $382,000 or $.58 per Mcfe for 2002. The higher per Mcfe expense in the second quarter of 2003 compared to 2002 was primarily due to charges for prior period gas processing fees in the Carbon area of central Alberta and an increase in the conversion rate of the Canadian dollar relative to the U.S. dollar.

General and administrative (G&A) expenses (net of overhead reimbursements on operated wells) incurred by Carbon USA increased 16% from $746,000 for the second quarter of 2002 to $867,000 for 2003. The increase was primarily due to legal and accounting fees of $161,000 associated with the announced merger with Evergreen. For the second quarter of 2002 and 2003, Carbon USA capitalized $41,000 of G&A related to geological and geophysical activities.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by Carbon Canada increased 46% from $415,000 for the second quarter of 2002 to $604,000 for 2003. The increase was primarily due to an increase in Carbon management service fees billed to Carbon Canada and an increase in the conversion rate of the Canadian dollar relative to the U.S. dollar. For the second quarter of 2002 and 2003, Carbon Canada did not capitalize any G&A related to geological and geophysical activities.

Interest and other expense incurred by Carbon USA decreased 74% from $207,000 for the second quarter of 2002 to $54,000 for 2003. The decrease was due primarily to decreased average debt balances in the second quarter of 2003 relative to 2002 due to the disposition of the Company's assets in the Permian Basin in March 2003 and the utilization of proceeds from the disposition to repay borrowings under the Company's U.S. credit facility.

Interest and other expense incurred by Carbon Canada increased 144% from $52,000 for the second quarter of 2002 to $127,000 for 2003. The increase was due primarily to increased average debt balances in the second quarter of 2003 relative to 2002, increased interest rates in 2003 and an increase in the conversion rate of the Canadian dollar relative to the U.S. dollar.

Depreciation, depletion and amortization (DD&A) of oil and gas assets is calculated using the units of production method. DD&A is typically determined by using historical capitalized costs incurred to find, develop and recover oil and gas reserves. However, the Company's DD&A rate has been affected by the purchase price of the properties acquired in the Company's acquisitions of Carbon USA and Carbon Canada, the volume of proved reserves the Company acquired in the acquisitions and a ceiling test impairment recorded by the Company in the second quarter of 2002.

DD&A expense incurred by Carbon USA was $392,000 or $.75 per Mcfe for the second quarter of 2003 compared to $1.0 million or $1.15 per Mcfe for 2002. The decreased rate is primarily due to the ceiling test impairment recorded by the Company in the second quarter of 2002 and a reduction to the full cost pool in the U.S. resulting from the disposition of the Company's assets in the Permian Basin in March 2003.

DD&A expense incurred by Carbon Canada was $812,000 or $1.05 per Mcfe compared to $663,000 or $1.01 per Mcfe for 2002. The increased rate is primarily due to increases to the full cost pool in Canada due to acquisitions made by the Company in the first quarter of 2003 and an increase in the conversion rate of the Canadian dollar relative to the U.S. dollar, partially offset by a ceiling test impairment recorded by the Company in the second quarter of 2002.

A non-cash ceiling test impairment of the Company's full cost pool was recorded in the second quarter of 2002 because the capitalized cost of its oil and natural gas reserves in the United States and Canada exceeded the ceiling limitation established for those reserves. The United States Securities and Exchange Commission (SEC) requires that public companies utilizing the full cost method of accounting for oil and gas properties perform a ceiling test at the end of each quarterly reporting period. The ceiling test limitation requires that capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of the present value of future net revenue from estimated production of proved oil and gas reserves using a 10% discount factor and unescalated oil and gas prices and costs as of the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects. Under the SEC guidelines, the natural gas and oil prices used to determine the future value of the Company's oil and gas reserves are based on posted prices on the last day of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements). The Company's ceiling test reflected the use of hedge adjusted prices in accordance with SEC guidelines.

At June 30, 2002, the Company used natural gas prices of $1.10 per MMBtu for Colorado and Utah and $1.43 per MMBtu for central Alberta. These prices were $2.32 per MMBtu for Colorado and Utah and $1.99 per MMBtu for Alberta less than the price for natural gas delivered to Henry Hub, the principal reference price for natural gas in the United States. The differential was considerably greater than the 36 month average historical differential at June 30, 2002 of $.37 per MMBtu for Colorado and Utah and $.29 per MMBtu for Alberta. The Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $14.0 million and $2.4 million, respectively. When product prices were adjusted for oil and natural gas hedges in place at June 30, 2002, the Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $12.0 million and $1.2 million, respectively. At June 30, 2002, the Company recorded a $12.0 million and $1.2 million non-cash charge in the United States and Canada, respectively, to reflect these impairments. See Note 2 to the Consolidated Financial Statements for additional information.

No provision for income tax expense was recorded by Carbon USA for the second quarter of 2003 as the Company recorded a deferred tax asset valuation allowance of $296,000. This compared to income tax expense of $1.1 million recorded by Carbon USA for the second quarter of 2002. Due primarily to the low commodity prices resulting in the full cost ceiling impairment recorded during the second quarter of 2002, the Company recorded a deferred tax asset valuation allowance of $5.5 million during the second quarter of 2002.

Income tax expense incurred by Carbon Canada was $639,000 for the second quarter of 2003, an effective tax rate of 47%, compared to a benefit of $424,000 and an effective tax rate of 47% for 2002. The effective rate for the second quarters of 2003 and 2002 were higher than the statutory rates primarily due to adjustments of deferred taxes related to adjustments of statutory tax rates.

On a consolidated basis, the effective tax rate of 109% for the second quarter of 2003 was primarily due to the deferred tax valuation allowance of $296,000 recorded by Carbon USA and the consolidation of Carbon's two reportable segments in which one reportable segment (Carbon USA) was in a net loss position and had a comparatively lower effective tax rate than its other reportable segment (Carbon Canada), which was in a net income position.

The following table and discussion present comparative revenue, production volumes, average sales prices, expenses and the percentage change between periods for the six months ended June 30, 2003 and 2002 for the Company's United States and Canadian operations.

All amounts are presented in U.S. dollars.

	United States Six Months Ended June 30,			**Canada Six Months Ended June 30,**		
	2003	**2002**	**Change**	**2003**	**2002**	**Change**
	(in thousands, except prices and per Mcfe information)			**(in thousands, except prices and per Mcfe information)**		
Revenues:						
Oil and gas revenues	$ 5,051	$ 4,839	4%	$ 7,226	$ 3,497	107%
Marketing and other, net	(216)	179	-221%			n/a
Total revenues	4,835	5,018	-4%	7,226	3,497	107%
Daily production volumes:						
Natural gas (MMcf)	6.4	8.8	-27%	7.5	6.3	19%
Oil and liquids (Bbl)	161	244	-34%	162	147	10%
Equivalent production (MMcfe 6:1)	7.4	10.3	-28%	8.5	7.2	18%

	United States Six Months Ended June 30,			Canada Six Months Ended June 30,		
Average price realized:						
Natural gas (Mcf)	$ 3.79	$ 2.01	89%	$ 4.80	$ 2.66	80%
Oil and liquids (Bbl)	22.38	20.53	9%	24.30	17.70	37%
Direct lifting costs	$ 683	$ 761	-10%	$ 1,006	$ 732	37%
Average direct lifting costs/Mcfe	0.51	0.41	-24%	0.78	0.56	39%
Other production costs	1,884	1,588	19%	31	82	-62%
General and administrative, net	1,844	1,624	14%	1,140	866	32%
Depreciation, depletion and amortization	1,147	2,116	-46%	1,508	1,321	14%
Full cost ceiling impairment		12,003	n/a		1,215	n/a
Interest and other expense, net	290	370	-22%	230	82	180%
Income tax provision (benefit)	(90)	746	-112%	1,282	(370)	446%

Revenues from oil and gas sales of Carbon USA for the first six months of 2003 were $5.1 million compared to $4.8 million, a 4% increase from 2002. The increase was due primarily to increased oil and natural gas prices, partially offset by decreased oil, liquids and natural gas production due to the disposition of the Company's Kansas assets in September 2002 and Permian Basin assets in March 2003.

Revenues from oil, liquids and gas sales of Carbon Canada for the first six months of 2003 were $7.2 million compared to $3.5 million, a 107% increase from 2002. The increase was due primarily to increased oil, liquids and natural gas prices and an increase in oil, liquids and natural gas production.

Average production in the United States for the first six months of 2003 was 161 barrels of oil and liquids per day and 6.4 million cubic feet (MMcf) of gas per day, a decrease of 28% from the same period in 2002 on a Mcf equivalent (Mcfe) basis where one barrel of oil or liquids is equal to six Mcf of gas. The decrease in production was primarily due to the disposition of the Company's Kansas assets in September 2002 and Permian Basin assets in March 2003. Exclusive of these disposed assets, average production in the United States for the first six months of 2003 increased 3% on a Mcfe basis compared to 2002. During the first six months of 2003, Carbon USA participated in the drilling of one gross (.1 net) oil well and two gross (1.5 net) gas wells compared to three gross (.2 net) oil wells during the first six months of 2002.

Average production in Canada for the first six months of 2003 was 162 barrels of oil and liquids per day and 7.5 MMcf of gas per day, an increase of 18% from the same period in 2002 on a Mcfe basis. The increase was primarily due to successful drilling activities in the third and fourth quarters of 2002 and the first and second quarters of 2003 in the Carbon and Rowley areas of central Alberta, partially offset by natural production declines in all operating areas. During the first six months of 2003, Carbon Canada participated in the drilling of ten gross (5.7 net) gas wells. During the first six months of 2002, Carbon Canada participated in the drilling of six gross (4.2 net) wells of which five gross (3.7 net) were completed as gas wells and one gross (.5 net) was abandoned as a dry hole.

Average oil and liquids prices realized by Carbon USA increased 9% from $20.53 per barrel for the first six months of 2002 to $22.38 for 2003. The average oil and liquids price includes hedging losses of $157,000 or $5.37 per barrel for the first six months of 2003 compared to hedging losses of $16,000 or $.35 per barrel for 2002. Average natural gas prices realized by Carbon USA increased 89% from $2.01 per Mcf for the first six months of 2002 to $3.79 for 2003. The average natural gas price includes hedge losses of $670,000 or $.57 per Mcf for the first six months of 2003 compared to hedge gains of $64,000 or $.04 per Mcf for 2002.

Average oil and liquids prices realized by Carbon Canada increased 37% from $17.70 per barrel for the first six months of 2002 to $24.30 for 2003. The average oil price includes hedge losses of $65,000 or $2.23 per barrel for the first six months of 2003 compared to hedge gains of $11,000 or $.07 per barrel for 2002. Average natural gas prices realized by Carbon Canada increased 80% from $2.66 per Mcf for the first six months of 2002 to $4.80 for 2003. The average natural gas price includes hedge losses of $284,000 or $.21 per Mcf for the first six months of 2003 compared to hedge gains of $16,000 or $.01 per Mcf for 2002.

Other losses in the United States for the first six months of 2003 were $216,000 compared to revenues of $179,000 for 2002. The loss for the first six months of 2003 was primarily due to losses of $272,000 on derivative instruments that did not qualify for hedge accounting treatment, partially offset by gathering revenues. Other revenues for the first six months of 2002 consisted primarily of gains of $122,000 on derivative instruments that did not qualify for hedge accounting treatment and gathering revenues.

Direct lifting costs incurred by Carbon USA were $683,000 or $.51 per Mcfe for the first six months of 2003 compared to $761,000 or $.41 per Mcfe for 2002. The higher per Mcfe expense in the second quarter of 2003 compared to 2002 was primarily due to workover expenses in the Piceance Basin and, exclusive of properties divested by the Company during the last twelve months, operating approximately the same number of wells with lower production per well.

Other production costs incurred by Carbon USA, consisting primarily of severance taxes, gathering and processing fees and production overhead, were $1.9 million for the first six months of 2003 compared to $1.6 million for 2002. The increase was primarily due to increased gathering and processing fees and increased production taxes due to increased natural gas and oil and liquids pricing, partially offset by decreased overhead expenses as a result of the disposition of the Company's assets in the Permian Basin in March 2003.

Direct lifting costs incurred by Carbon Canada were $1.0 million or $.78 per Mcfe for the first six months of 2003 compared to $732,000 or $.56 per Mcfe for 2003. The higher per Mcfe expense for the first six months of 2003 compared to 2002 was primarily due to charges for prior period gas processing fees in the Carbon area of central Alberta and an increase in the conversion rate of the Canadian dollar relative to the U.S. dollar.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by Carbon USA increased 14% from $1.6 million for the first six months of 2002 to $1.8 million for 2003. The increase was primarily due to investment banking, legal and accounting fees of $478,000 associated with the announced merger with Evergreen, partially offset by increased Carbon management service fees billed to Carbon Canada.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by Carbon Canada increased 32% from $866,000 for the first six months of 2002 to $1.1 million for 2003. The increase was primarily due to an increase in Carbon management service fees billed to Carbon Canada and an increase in the conversion rate of the Canadian dollar relative to the U.S. dollar.

Interest and other expense incurred by Carbon USA decreased 22% from $370,000 for the first six months of 2002 to $290,000 for 2003. The decrease was due primarily to decreased average debt balances in the first six months of 2003 relative to 2002 due to the disposition of the Company's assets in the Permian Basin in March 2003 and the utilization of proceeds from the disposition to repay borrowings under the Company's U.S. credit facility.

Interest and other expense incurred by Carbon Canada increased 180% from $82,000 for the first six months of 2002 to $230,000 for 2003. The increase was due primarily to increased average debt balances in the first six months of 2003 relative to 2002, increased interest rates in 2003 and an increase in the conversion rate of the Canadian dollar relative to the U.S. dollar.

Depreciation, depletion and amortization (DD&A) of oil and gas assets is calculated using the units of production method. DD&A is typically determined by using historical capitalized costs incurred to find, develop and recover oil and gas reserves. However, the Company's DD&A rate has been determined primarily by the purchase price incurred by the Company in its acquisitions of Carbon USA and Carbon Canada, the volume of proved reserves the Company acquired in the acquisitions and a ceiling test impairment recorded by the Company in the second quarter of 2002.

DD&A expense incurred by Carbon USA was $2.1 million or $1.14 per Mcfe for the first six months of 2002 compared to $1.1 million or $.86 per Mcfe for 2003. The decreased rate is due primarily to the ceiling test impairment recorded by the Company in the second quarter of 2002 and a reduction to the full cost pool in the U.S. resulting from the disposition of the Company's assets in the Permian Basin in March 2003.

DD&A expense incurred by Carbon Canada was $1.3 million or $1.02 per Mcfe compared to $1.5 million or $1.16 per Mcfe for 2003. The increased rate is due to increases to the full cost pool in Canada due to acquisitions made by the Company in the first quarter of 2003 and an increase in the conversion rate of the Canadian dollar relative to the U.S. dollar, partially offset by a ceiling test impairment recorded by the Company in the second quarter of 2002.

A non-cash ceiling test impairment of the Company's full cost pool was recorded in the second quarter of 2002 because the capitalized cost of its oil and natural gas reserves in the United States and Canada exceeded the ceiling limitation established for those reserves. The United States Securities and Exchange Commission (SEC) requires that public companies utilizing the full cost method of accounting for oil and gas properties perform a ceiling test at the end of each quarterly reporting period. The ceiling test limitation requires that capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of the present value of future net revenue from estimated production of proved oil and gas reserves using a 10% discount factor and unescalated oil and gas prices and costs as of the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects. Under the SEC guidelines, the natural gas and oil prices used to determine the future value of the Company's oil and gas reserves are based on posted prices on the last day of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements). The Company's ceiling test reflected the use of hedge adjusted prices in accordance with SEC guidelines.

At June 30, 2002, the Company used natural gas prices of $1.10 per MMBtu for Colorado and Utah and $1.43 per MMBtu for central Alberta. These prices were $2.32 per MMBtu for Colorado and Utah and $1.99 per MMBtu for Alberta less than the price for natural gas delivered to Henry Hub, the principal reference price for natural gas in the United States. The differential was considerably greater than the 36 month average historical differential at June 30, 2002 of $.37 per MMBtu for Colorado and Utah and $.29 per MMBtu for Alberta. The Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $14.0 million and $2.4 million, respectively. When product prices were adjusted for oil and natural gas hedges in place at June 30, 2002, the Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $12.0 million and $1.2 million, respectively. At June 30, 2002, the Company recorded a

$12.0 million and $1.2 million non-cash charge in the United States and Canada, respectively, to reflect these impairments. See Note 2 to the Consolidated Financial Statements for additional information.

Income tax benefit recorded by Carbon USA was $90,000 for the first six months of 2003, an effective tax rate of 9% as the Company recorded a deferred tax asset valuation allowance of $290,000. This compares to an expense of $746,000 for the six months ended June 30, 2002. Due primarily to the low commodity prices resulting in the full cost ceiling impairment recorded during the second quarter of 2002, the Company recorded a deferred tax asset valuation allowance of $5.5 million during the second quarter of 2002.

Income tax expense incurred by Carbon Canada was $1.3 million for the first six months of 2003, an effective tax rate of 39%, compared to a tax benefit of $370,000 and an effective tax rate of 46% for 2002. The higher effective tax rate for the first six months of 2002 compared to 2003 was primarily due to an adjustment of deferred taxes for the first six months of 2002 related to changes in statutory tax rates and a decrease in the non-deductibility of certain Canadian royalties for oil, liquids and natural gas compared to an allowable special deduction for Canadian resource properties for the first six months of 2003.

On a consolidated basis, the effective tax rate of 52% for the first six months of 2003 was primarily due to the deferred tax valuation allowance of $290,000 recorded by Carbon USA and the consolidation of Carbon's two reportable segments in which one reportable segment (Carbon USA) was in a net loss position and had a comparatively lower effective tax rate than its other reportable segment (Carbon Canada), which was in a net income position.

Liquidity and Capital Resources

At June 30, 2003, the Company had $55.7 million of assets. Total capitalization was $38.5 million, consisting of 58% stockholders' equity and 42% debt.

For a discussion of the Company's credit facilities, see Note 4 to the Consolidated Financial Statements in this report.

Net cash provided by operations for the six months ended June 30, 2003 was $4.1 million compared to $511,000 used in operations in 2002. The increase in operating cash flow was primarily due to an increase in oil and gas revenues due to increased oil, liquids, and natural gas prices in all regions and increased oil, liquids and natural gas production in Canada, partially offset by decreased oil, liquids and natural gas production in the United States. The increase was also due to comparative changes in working capital as the Company paid large tax liabilities and trade payables during the six months ended June 30, 2002 that were accrued at December 31, 2001.

For the six months ended June 30, 2003, Carbon USA spent approximately $2.4 million primarily to fund development and exploration activities in Colorado and Utah and received $14.5 million in proceeds related to the disposition of its interest in oil and gas properties located primarily in the Permian Basin of southeast New Mexico. For the six months ended June 30, 2003, Carbon Canada spent approximately $7.7 million primarily to fund acquisition, development and exploration activities in central and northwest Alberta.

Carbon's primary cash requirements for the remainder of 2003, subject to completion of the proposed merger described previously, will be to fund exploration and development expenditures, finance acquisitions, repay debt, and for general working capital needs. The Company has budgeted capital expenditures for the remainder of 2003, exclusive of unplanned acquisitions or divestitures, of approximately $11.6 million. At June 30, 2003, the Company is in compliance with all its debt covenants and has no reason to believe that either of its credit facilities will require principal payments during the next twelve months. Under the facilities, funds available at June 30, 2003 were approximately $13.9 million. Carbon believes that available borrowings under its credit agreements and projected operating cash flows will be sufficient to cover its working capital, planned capital expenditures and debt service requirements for the next 12 months.

On March 24, 2003, Carbon USA closed on the sale of its interest in oil and gas properties located primarily in the Permian Basin of southeast New Mexico. Net proceeds from the sale, after normal closing adjustments, were $14.4 million. The Company initially utilized the proceeds to repay borrowings under the Company's U.S. credit facility and anticipates utilizing the resulting additional borrowing capacity to fund its future exploration and development drilling program in the Piceance and Uintah Basins.

The Company's future cash flow is subject to a number of variables, including the level of production, commodity prices and capital expenditures. Also, borrowings under Carbon's credit facilities are subject to a number of conditions, including compliance with various covenants and borrowing base calculations. As a result, there can be no assurance that operating cash flows and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or to meet other cash needs.

The table below sets forth the Company's contractual obligations at June 30, 2003 and the effect such obligations are expected to have on its liquidity and cash flow in future periods (in thousands):

Contractual Obligations	Payments Due By Period Less than 1 Year	1 - 3 Years	4 - 5 Years
Revolving credit facilities	$	$ 16,343	$
Operating leases	287	235	
Transporation agreements	130	62	
	$ 417	$ 16,640	$

Disclosures Regarding Forward-Looking Statements

All statements contained in this filing that are not historical facts are forward-looking statements. Such statements address activities, events or developments that the Company expects, believes, projects, intends or anticipates will or may occur, including such matters as future capital, development and exploration expenditures, reserve estimates (including estimates of future net revenues associated with such reserves and the present value of such future net revenues), future production of oil and natural gas, business strategies, expansion and growth of the Company's operations, cash flow and anticipated liquidity, prospect development and property acquisition, obtaining financial or industry partners for prospect or program development, or marketing of oil and natural gas. Although the Company believes that the expectations reflected in the forward-looking statements and the assumptions upon which such forward-looking statements are based are reasonable, it can give no assurance that such expectations and assumptions will prove to be correct. Factors that could cause actual results to differ materially are described, among other places, in the Marketing, Competition, Government Regulation, Environmental Regulation and Operating Hazards sections of the Company's Annual Report on Form 10-K and 10-K/A for the year ended December 31, 2002 and under "Management's Discussion and Analysis of Financial Condition and Results of Operations." These factors include, but are not limited to, general economic conditions, the market price of oil and natural gas, the risks associated with exploration, the Company's ability to find, acquire, market, develop and produce new properties, operating hazards attendant to the oil and natural gas business, uncertainties in the estimation of proved reserves and in the projection of future rates of production and timing of development expenditures, the strength and financial resources of the Company's competitors, the Company's ability to find and retain skilled personnel, climatic conditions, labor relations, availability and cost of material and equipment, environmental risks, the results of financing efforts, and regulatory developments. All written and oral forward-looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements. The Company undertakes no obligation to update any forward-looking statements to reflect future events or developments.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

Because of its debt position, the Company is exposed to interest rate risk. Interest rate risk is estimated as the potential change in the fair value of interest sensitive investments resulting from an immediate hypothetical change in interest rates. The sensitivity analysis presents the change in fair value of these instruments and changes in the Company's earnings and cash flows assuming an immediate one percent change in floating interest rates. At June 30, 2003, the Company had $4.7 million of floating rate debt through its facility with Bank of Oklahoma and $11.6 million through its facility with CIBC. Assuming constant debt levels, the impact on earnings and cash flow for the twelve month period beginning July 1, 2003, from a one percent change in interest rates would be approximately $163,000 before taxes.

Foreign Currency Risk

The Canadian dollar is the functional currency of Carbon Canada. The Company is subject to foreign currency exchange rate risk on cash flows relating to sales, expenses, financing and investing transactions. The Company has not entered into foreign currency forward contracts or other similar financial instruments to manage this risk.

Commodity Price Risk

Oil and gas commodity markets are influenced by global and regional supply and demand factors. Worldwide political events can also impact commodity prices. The prices received by Carbon for its natural gas production are determined mainly by factors affecting North American regional supply and demand for natural gas. Based upon recent reportable events, it is possible that published indices used to establish the price received by producers for their natural gas production may not be an accurate indication of the market price for natural gas.

At June 30, 2003, all of the Company's United States gas production is in Colorado and Utah. Since March 2002, natural gas prices for production in these areas have been unusually low relative to the rest of the producing areas in the United States. Reduced regional seasonal demand and inadequate pipeline transportation capacity linking Carbon's production in the Piceance and Uintah Basins to consuming regions are principal factors contributing to the large price differentials. While there is the prospect of additional pipeline capacity out of the region which is expected to help alleviate the high price differentials received by Rocky Mountain gas producers, continued volatility is expected to affect the price received for natural gas produced by Carbon in the United States and Canada.

The Company may use certain financial instruments including swaps, collars, futures and other contracts in an attempt to reduce exposure to fluctuations in the price of oil and natural gas by establishing fixed prices or hedges for its oil and natural gas production. Hedging the Company's oil and natural gas production may limit the Company's exposure to price declines or limit the benefit of price increases. Risks associated with the practice of hedging include counterparty credit risk, Carbon's inability to deliver required physical volumes of oil and gas which support the Company's hedges, inefficient hedges, basis risk, inability to liquidate hedge positions if desired and other unforeseen economic factors.

The table below sets forth the Company's derivative financial instrument positions related to its natural gas and oil production at June 30, 2003:

Swaps:

Carbon USA				**Carbon Canada**			
Time Period	**Bbl/ MMBtu**	**Weighted Average Fixed Price Bbl/ MMBtu**	**Derivative Asset/ (Liability)**	**Time Period**	**Bbl/ MMBtu**	**Weighted Average Fixed Price Bbl/ MMBtu**	**Derivative Asset/ (Liability)**
			(in thousands)				**(in thousands)**
Gas				**Gas**			
07/01/03-12/31/03	675,000	$ 3.07	$ (1,107)	07/01/03-12/31/03	87,000	$ 3.42	$ (122)
Oil				**Oil**			
07/01/03-12/31/03	18,400	$ 25.63	$ (61)	07/01/03-12/31/03	18,400	$ 29.68	$ 14

The Company periodically enters into long-term physical sales contracts for a portion of its natural gas and oil production. The table below sets forth physical fixed price and costless collar contracts at June 30, 2003:

Fixed price:

Carbon Canada		
Time Period	**MMBtu**	**Weighted Average Fixed Price MMBtu**
Gas		
07/01/03-12/31/03	494,000	$ 4.05

Costless collars:

Carbon Canada			
Time Period	**MMBtu**	**Weighted Average Fixed Price MMBtu**	**Weighted Average Ceiling Price MMBtu**
Gas			
07/01/03-12/31/03	203,000	$ 4.28	$ 5.62
01/01/04-04/30/04	115,000	4.28	6.26

Item 4. CONTROLS AND PROCEDURES

The Company's management, with the participation of the Company's principal executive officer and principal financial officer, carried out an evaluation of the effectiveness of the design and operation of the Company's disclosure controls and procedures as of June 30, 2003. Based upon this evaluation, the Company's principal executive officer and principal financial officer concluded that the Company's disclosure controls and procedures were effective as of that date for purposes of recording, processing, summarizing and timely reporting material information required to be disclosed in reports that the Company files under the Exchange Act.

There were not any changes in the Company's internal control over financial reporting that occurred during the Company's quarter ended June 30, 2003 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II OTHER INFORMATION

Item 1-5 Not applicable.

Item 6 (a) Exhibits

31.1 Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*

31.2 Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*

32.1 Certification of Chief Executive Officer, dated September 15, 2003 pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

32.2 Certification of Chief Financial Officer, dated September 15, 2003 pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

(b) Reports on Form 8-K

(i) A report on Form 8-K, filed with the Securities and Exchange commission on April 1, 2003, regarding the March 31, 2003 announcement of an Agreement and Plan of Reorganization between Carbon Energy Corporation, Evergreen Resources, Inc. and Evergreen Merger Corporation.

(ii) A report on Form 8-K, filed with the Securities and Exchange commission on April 8, 2003, regarding the March 24, 2003 sale of the Company's interests in oil and gas properties located primarily in the Permian Basin of southeast New Mexico.

(iii) A report on Form 8-K, filed with the Securities and Exchange commission on May 16, 2003, regarding the May 15, 2003 press release announcing the Company's financial results for the three months ended March 31, 2003.

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* Filed or furnished herewith

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

CARBON ENERGY CORPORATION
Registrant

Date: September 15, 2003 By: /s/ PATRICK R. MCDONALD

President and Chief Executive Officer

Date: September 15, 2003 By: /s/ KEVIN D. STRUZESKI

Treasurer and Chief Financial Officer

EXHIBIT INDEX

Description of Exhibit

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