CARBON ENERGY CORP
Form 10-Q
November 14, 2002

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2002

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

Class	Outstanding at November 11, 2002
Common stock, no par value	6,135,823 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)

	September 30, 2002	December 31, 2001
ASSETS		
Current assets:		
Cash	$	$
Accounts receivable, trade	2,373	2,258
Accounts receivable, other	26	53
Prepaid expenses and other	821	317

	September 30, 2002	December 31, 2001
Current derivative asset		341
Total current assets	3,220	2,969
Property and equipment, at cost:		
Oil and gas properties, using the full cost method of accounting:		
Unproved properties	8,035	7,500
Proved properties	66,850	62,750
Furniture and equipment	933	927
	75,818	71,177
Less accumulated depreciation, depletion and amortization	(30,056)	(12,226)
Property and equipment, net	45,762	58,951
Deposits and other long-term assets	582	448
Total assets	$ 49,564	$ 62,368

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

CARBON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands)

(unaudited)

	September 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 3,352	$ 5,113
Accrued production taxes payable	510	527
Income taxes payable		1,168
Undistributed revenue and other	1,068	1,062
Current derivative liability	976	76
Deferred income taxes		74
Total current liabilities	5,906	8,020
Long-term debt	22,417	17,870
Other long-term liabilities	237	18
Deferred income taxes	2,747	2,577
Minority interest	27	29
Stockholders' equity:		

	September 30, 2002	December 31, 2001
Preferred stock, no par value:		
10,000,000 shares authorized, none outstanding		
Common stock, no par value:		
20,000,000 shares authorized, 6,111,902 and 6,079,225 shares issued and outstanding at September 30, 2002 and December 31, 2001, respectively	31,958	31,799
Retained earnings (accumulated deficit)	(12,336)	2,538
Accumulated other comprehensive loss	(1,392)	(483)
Total stockholders' equity	18,230	33,854
Total liabilities and stockholders' equity	$ 49,564	$ 62,368

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 September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Revenues:				
Oil and gas sales	$ 3,657	$ 4,104	$ 11,241	$ 17,471
Marketing and other, net	88	(395)	267	857
	3,745	3,709	11,508	18,328
Expenses:				
Oil and gas production costs	1,347	1,267	3,758	3,896
Depreciation, depletion and amortization	1,228	1,564	4,665	4,400
Full cost ceiling impairment			13,218	
General and administrative, net	1,060	1,051	3,550	3,365
Interest and other, net	306	196	758	631
Total operating expenses	3,941	4,078	25,949	12,292
Income (loss) before income taxes	(196)	(369)	(14,441)	6,036
Income tax provision (benefit):				
Current	(55)	184	5	1,672
Deferred	112	(249)	428	838
Total taxes	57	(65)	433	2,510
	(253)	(304)	(14,874)	3,526

	Three Months Ended September 30,		Nine Months Ended September 30,	
Income (loss) before cumulative effect of change in accounting principle				
Cumulative effect of change in accounting principle, net of tax				(1,510)
Net income (loss)	$ (253)	$ (304)	$ (14,874)	$ 2,016
Average number of common shares outstanding:				
Basic	6,108	6,070	6,097	6,048
Diluted	6,108	6,070	6,097	6,291
Earnings (loss) per share basic:				
Income (loss) before cumulative effect of change in accounting principle	$ (0.04)	$ (0.05)	$ (2.44)	$ 0.58
Cumulative effect of change in accounting principle, net of tax				(0.25)
	$ (0.04)	$ (0.05)	$ (2.44)	$ 0.33
Earnings (loss) per share diluted:				
Income (loss) before cumulative effect of change in accounting principle	$ (0.04)	$ (0.05)	$ (2.44)	$ 0.56
Cumulative effect of change in accounting principle, net of tax				(0.24)
	$ (0.04)	$ (0.05)	$ (2.44)	$ 0.32

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 Nine Months Ended September 30,	
	2002	**2001**
Cash flows from operating activities:		
Net income (loss)	$ (14,874)	$ 2,016
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization expense	4,665	4,400
Full cost ceiling impairment	13,218	
Amortization of deferred hedging gains	(180)	
Unrealized derivative gains		(1,713)
Deferred income tax	428	838
Cumulative effect of change in accounting principle		1,510

	For the Nine Months Ended September 30,	
Minority interest	(2)	26
Vesting of restricted stock grants	120	96
Changes in operating assets and liabilities:		
Decrease (increase) in:		
Accounts receivable	73	2,994
Amounts due from broker		3,793
Prepaid expenses and other assets	(175)	966
Increase (decrease) in:		
Accounts payable and accrued expenses	(1,989)	(3,902)
Undistributed revenue	9	(341)
Net cash provided by operating activities	1,293	10,683
Cash flows from investing activities:		
Capital expenditures for oil and gas properties	(8,580)	(17,122)
Proceeds from property sales	2,651	6,758
Acquisition of CEC Resources		(203)
Capital expenditures for support equipment	(6)	(521)
Net cash used in investing activities	(5,935)	(11,088)
Cash flows from financing activities:		
Proceeds from notes payable	19,970	39,719
Principal payments on notes payable	(15,401)	(39,470)
Proceeds from issuance of common stock	39	180
Net cash provided by financing activities	4,608	429
Effect of exchange rate changes on cash	34	(45)
Net increase (decrease) in cash		(21)
Cash, beginning of period		21
Cash, end of period	$	$
Supplemental cash flow information:		
Cash paid for interest	$ 772	$ 743
Cash paid for taxes	1,336	461

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 (Carbon) is an 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 exploration and production areas in the United States include the Piceance Basin in Colorado, the Uintah Basin in Utah, the Permian Basin in New Mexico and Montana. The Company's exploration and production areas in Canada include Central Alberta and Southeast Saskatchewan.

Carbon was incorporated in September 1999 under the laws of the State of Colorado to facilitate the acquisition of Bonneville Fuels Corporation (BFC) and subsidiaries. The acquisition of BFC closed on October 29, 1999 and was accounted for as a purchase. In February 2000, Carbon completed an offer to exchange shares of Carbon for shares of CEC Resources Ltd. (CEC), an Alberta, Canada company. The exchange offer resulted in the issuance of 1,482,826 shares of Carbon stock in exchange for over 97% of the outstanding CEC shares. The acquisition closed on February 17, 2000 and was also accounted for as a purchase. In November 2000, CEC initiated an offer to purchase additional shares of CEC. The offer was completed in February 2001 with the acquisition of approximately 34,000 shares of CEC stock. Carbon currently owns 99.7% of the stock of CEC. On July 11, 2002, Carbon changed the name of BFC to Carbon Energy Corporation (USA) (Carbon USA). In October 2002, CEC initiated a consolidation of outstanding shares by which the remaining .3% of CEC shares currently not owned by Carbon will be acquired by CEC. It is anticipated that the consolidation of shares will be completed in January 2003, at which time Carbon will own 100% of the outstanding shares of CEC. Collectively, Carbon, CEC, Carbon USA and its subsidiaries are referred to as the Company.

All amounts are presented in U.S. dollars.

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 certain information and note disclosures required by accounting principles generally accepted in the United States for complete financial statements. The accompanying consolidated financial statements of the Company should be read in conjunction with the consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K, for the year ended December 31, 2001, 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 September 30, 2002 and the results of its operations and its cash flows for the periods presented.

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, except CEC, of which the Company owns approximately 99.7%. All significant intercompany transactions and balances have been eliminated.

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. The estimated future cost of site restoration, dismantlement and abandonment activities is 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, total 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 un-escalated 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.

At June 30, 2002, 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 pricing at June 30, 2002 was 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 the impairments. The impairments were included as additional accumulated depreciation, depletion and amortization (DD&A) in the accompanying balance sheet. At September 30, 2002, the capitalized 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 additional 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.

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 (overproduced) or less (underproduced) 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 will not be sufficient to enable the underproduced owner to recoup its share of production, revenue is deferred and a liability is created.

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 tax rates in effect for the year in which the differences are expected to reverse.

Interest Rate Swap Agreements During 2002, the Company entered into interest rate swap agreements that effectively convert 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. Gains or losses from interest rate swaps that qualify for hedge accounting treatment are recognized as an adjustment to interest expense in the period in which the financial instrument matures. Gains or losses from interest rate swaps that do not qualify for hedge accounting treatment are recognized in the current period as other income or expense. 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 September 30, 2002:

Notional Amount	Contract Expiration Date	LIBOR Fixed Rate	Derivative Asset/ (Liability)
(in thousands)			
$ 3,700	May 2003	3.46%	$ (51)
2,000	October 2003	3.77%	(53)
800	October 2003	3.82%	(22)
1,000	March 2004	4.15%	(35)
2,500	April 2004	4.24%	(104)

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. The Company has a Risk Management Committee to administer and approve all production hedging 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. Gains or losses from financial instruments that do not qualify for hedge accounting treatment are recognized in the current period as other income or expense. 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 nine month periods ended September 30, 2002 and 2001 (in thousands):

	United States Three Months Ended September 30,	Canada Three Months Ended September 30,	United States Nine Months Ended September 30,	Canada Nine Months Ended September 30,

	2002	2001	2002	2001	2002	2001	2002	2001
Oil	$ (34)	$	$ (9)	$	$ (50)	$	$ 2	$
Natural gas	308	(280)	118	191	373	(1,567)	134	(730)

The table below sets forth the Company's derivative financial instrument positions relating to its natural gas and oil production that qualify for hedge accounting treatment at September 30, 2002:

Swaps:

Carbon USA Contracts				CEC Contracts			
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**			
10/01/02-12/31/02	322,000	$ 2.61	$ (125)	10/01/02-12/31/02	160,000	$ 2.43	$ (140)
01/01/03-12/31/03	1,400,000	3.07	(384)	01/01/03-12/31/03	216,000	2.82	(174)
Oil				**Oil**			
10/01/02-12/31/02	9,200	$ 24.55	$ (46)				
01/01/03-12/31/03	46,000	25.42	(22)	01/01/03-12/31/03	37,000	$ 25.37	$ (30)

Collars:

CEC Contracts				
Time Period	Bbl/ MMBtu	Average Floor Price Bbl/ MMBtu	Average Ceiling Price Bbl/ MMBtu	Derivative Asset/ (Liability)
				(in thousands)
Gas				
10/01/02-10/31/02	29,000	$ 2.41	$ 3.40	$ -
Oil				
10/01/02-12/31/02	9,200	$ 22.00	$ 27.50	$ (27)

The Company may enter into long-term physical sales contracts for a portion of its natural gas and oil production. The table below sets forth fixed price sales contracts at September 30, 2002:

Fixed price contracts:

Carbon USA Contracts			CEC Contracts		
Time Period	MMBtu	Weighted Average Fixed Price MMBtu	Time Period	MMBtu	Weighted Average Fixed Price MMBtu
Gas			**Gas**		
10/01/02-12/31/02	184,000	$ 2.57	10/01/02-12/31/02	174,000	$ 2.96
01/01/03-03/31/03	180,000	2.57	01/01/03-12/31/03	778,000	$ 3.16

During the first nine months of 2002, net hedging gains of $376,000 ($227,000 after tax) were transferred from accumulated other comprehensive income to earnings. The change in the fair market value of outstanding derivative contracts designated as hedges decreased by $1.1 million ($645,000 after tax). 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, no ineffectiveness was recognized related to the Company's hedge contracts during the first nine months of 2002. As of September 30, 2002, the Company had net unrealized derivative losses of $1.2 million ($692,000 after tax). Based on the expected prices for oil and gas as determined by financial commodity price markets at September 30, 2002, the Company expects to reclassify $976,000 of these net unrealized losses to earnings during the next twelve month period.

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/(losses) of $74,000 and ($440,000) for the nine months ended September 30, 2002 and 2001, 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 which are classified as other comprehensive income. The following table

sets forth the calculation of comprehensive income for the nine months ended September 30, 2002 and 2001:

	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
	(in thousands)	
Net income (loss)	$ (14,874)	$ 2,016
Other comprehensive income (loss), net of tax:		
Currency translation adjustment	74	(440)
Cumulative effect of change in accounting principle January 1, 2001		(2,768)
Reclassification adjustment for settled hedge contracts	(338)	1,381
Changes in fair value of outstanding hedge positions	(645)	1,714
Other comprehensive income (loss)	(909)	(113)
Comprehensive income (loss)	$ (15,783)	$ 1,903

In 2001, the Company entered into certain commodity derivative contracts with Enron North America Corp. (ENAC), a subsidiary of Enron Corp. (Enron). On December 2, 2001, Enron and ENAC filed for Chapter 11 bankruptcy, and the Company determined that the ENAC contracts no longer qualified for cash flow hedge accounting under Statement of Financial Accounting Standards No. 133 (SFAS No. 133). Consequently, the Company recorded a loss for the year ended December 31, 2001, based on the estimated fair value of the derivative contracts as determined by the future commodity price markets and deferred a corresponding amount in accumulated other comprehensive income.

The amount deferred in accumulated other comprehensive income at September 30, 2002 will be reclassified to earnings during the remainder of 2002 based on the originally scheduled settlement periods of the contracts. Amounts expected to be reclassified to earnings in the fourth quarter of 2002 are $66,000. Marketing and other revenue for the three and nine months ended September 30, 2002 include $58,000 and $180,000, respectively, of amounts reclassified from accumulated other comprehensive income related to these contracts.

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 quarter and nine months ended September 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 June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, "Business Combinations," which addresses financial accounting and

reporting for business combinations. SFAS No. 141 is effective for all business combinations initiated after June 30, 2001. The adoption of SFAS No. 141 did not have a material impact on the Company's financial position or results of operations.

In June 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets," which addresses, among other things, the financial accounting and reporting for goodwill subsequent to an acquisition. The new standard eliminates the requirement to amortize acquired goodwill; instead, such goodwill shall be reviewed at least annually for impairment. SFAS No. 142 is effective for the Company in 2002. The adoption of SFAS No. 142 did not have a material impact on the Company's financial position or results of operations.

In July 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which 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 liability will be allocated to operating expense by using a systematic and rational method. The statement is effective for the Company in 2003. The Company is currently evaluating what effect the adoption of this statement will have on its financial statements.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which provides a single accounting model for long-lived assets to be disposed of and changes the criteria that would have to be met to classify an asset as held-for-sale. The statement also requires expected future operating losses from discontinued operations to be recognized in the periods in which the losses are incurred, which is a change from the current requirement of recognizing such operating losses as of the measurement date. SFAS No. 144 is effective for the Company in 2002. The adoption of SFAS No. 144 did not have a material effect on the Company's financial position or results of operations.

3. Acquisition and Disposition of Assets

Acquisition of CEC Resources Ltd. In February 2000, Carbon completed an offer to exchange shares of Carbon for shares of CEC, an Alberta, Canada company. The exchange offer resulted in the issuance of 1,482,826 shares of Carbon stock in exchange for over 97% of the outstanding CEC shares. The acquisition closed on February 17, 2000 and was accounted for as a purchase. In November 2000, CEC initiated an offer to purchase additional shares of CEC. The offer was completed in February 2001 with the acquisition of approximately 34,000 shares of CEC stock. Carbon currently owns 99.7% of the stock of CEC. In October 2002, CEC initiated a consolidation of outstanding shares by which the remaining .3% of CEC shares currently not owned by Carbon will be acquired by CEC. It is anticipated that the consolidation of shares will be completed in January 2003 at which time Carbon will own 100% of the outstanding shares of CEC. See Note 1 to the Consolidated Financial Statements for additional information.

Disposition of Oil and Gas Assets In January 2001, the Company sold its entire working interests and related leasehold rights in the San Juan Basin, receiving net proceeds of approximately

$6.8 million. Proceeds from the sale were credited directly to the full cost pool and no gain or loss was recognized.

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 $2.0 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.

4. Long-term Debt

United States Credit Facility The Company's credit facility is an oil and gas reserve based line-of-credit with Wells Fargo Bank West National Association (Wells Fargo). At September 30, 2002, the borrowing base was $18.4 million with outstanding borrowings of $16.2 million. The borrowing base is subject to a $400,000 per month reduction through January 1, 2003, at which time the borrowing base will be $16.8 million. The facility has a maturity date of July 1, 2005 with no principal payments required until that date. The facility is secured by certain U.S. oil and gas properties of the Company. The facility bears interest at a rate equal to LIBOR plus 1.75% or Wells Fargo Prime, at the option of the Company. The Company's weighted average effective interest rate was approximately 3.7% at September 30, 2002. The borrowing base is based upon the lender's evaluation of the Company's proved oil and gas reserves, generally determined semi-annually.

The credit agreement 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 September 30, 2002.

The Company is presently in the process of securing a United States credit facility from the Bank of Oklahoma, National Association (Bank of Oklahoma), to replace the current facility with Wells Fargo. The Company has received a commitment letter from the Bank of Oklahoma regarding the facility, which is subject to certain conditions. According to the commitment letter, the initial borrowing base will be $19.0 million and the new credit facility will mature in three years. No principal payments will be required until maturity. The facility will be secured by certain U.S. oil and gas properties of the Company and will contain various covenants 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 will also be required to maintain certain financial ratios. The Company expects to complete this process before the end of 2002.

Canadian Credit Facility The Company's credit facility is an oil and gas reserve based line-of-credit with Canadian Imperial Bank of Commerce (CIBC). At September 30, 2002, the borrowing base was $8.8 million with outstanding borrowings of $6.3 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, 2003. 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 October 2003 at the earliest. As such, no amounts under the CIBC facility have been classified as current on the September 30, 2002 balance sheet. The Canadian facility bears interest at a rate equal to banker's acceptance rates plus 1.5% or at the CIBC Prime rate plus .5%. The Company's weighted average effective interest rate was approximately 5.0% at September 30, 2002.

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 September 30, 2002.

The agreement with CIBC also provides for $3.5 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 2 to the Consolidated Financial Statements.

5. Business and Geographical Segments

Segment information has been prepared in accordance with SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information." Carbon has two reportable business and geographic segments: Carbon USA and CEC, representing oil and gas operations in the United States and Canada, respectively. The segments are business units that operate in unique geographic locations.

The segment data presented below for the three and nine month periods ended September 30, 2002 and 2001 was prepared on the same basis as Carbon's consolidated financial statements.

	Three Months Ended September 30, 2002			Nine Months Ended September 30, 2002		
	United States	Canada	Total	United States	Canada	Total
Revenues:						

	Three Months Ended September 30, 2002			Nine Months Ended September 30, 2002		
Oil and gas sales	$ 2,121	$ 1,536	$ 3,657	$ 6,208	$ 5,033	$ 11,241
Marketing and other, net	88		88	267		267
	2,209	1,536	3,745	6,475	5,033	11,508
Expenses:						
Oil and gas production costs	857	490	1,347	2,454	1,304	3,758
Depreciation, depletion and amortization	686	542	1,228	2,802	1,863	4,665
Full cost ceiling impairment				12,003	1,215	13,218
General and administrative, net	624	436	1,060	2,248	1,302	3,550
Interest and other, net	222	84	306	592	166	758
Total operating expenses	2,389	1,552	3,941	20,099	5,850	25,949
Loss before income taxes	(180)	(16)	(196)	(13,624)	(817)	(14,441)
Income tax provision (benefit)		57	57	746	(313)	433
Net loss	$ (180)	$ (73)	$ (253)	$ (14,370)	$ (504)	$ (14,874)
Total assets	$ 28,712	$ 20,852	$ 49,564	$ 28,712	$ 20,852	$ 49,564
Capital expenditures	$ 2,411	$ 1,422	$ 3,833	$ 3,700	$ 4,880	$ 8,580

	Three Months Ended September 30, 2001			Nine Months Ended September 30, 2001		
	United States	Canada	Total	United States	Canada	Total
Revenues:						
Oil and gas sales	$ 1,985	$ 2,119	$ 4,104	$ 8,255	$ 9,216	$ 17,471
Marketing and other, net	(395)		(395)	857		857
	1,590	2,119	3,709	9,112	9,216	18,328
Expenses:						
Oil and gas production costs	895	372	1,267	2,714	1,182	3,896
Depreciation, depletion and amortization	901	663	1,564	2,442	1,958	4,400
General and administrative, net	646	405	1,051	2,033	1,332	3,365
Interest and other, net	164	32	196	481	150	631
Total operating expenses	2,606	1,472	4,078	7,670	4,622	12,292
Income (loss) before income taxes	(1,016)	647	(369)	1,442	4,594	6,036
Income tax provision (benefit)	(382)	317	(65)	540	1,970	2,510
Income (loss) before cumulative effect of change in accounting principle	(634)	330	(304)	902	2,624	3,526
Cumulative effect of change in accounting principle, net of tax				(1,510)		(1,510)
Net income (loss)	$ (634)	$ 330	$ (304)	$ (608)	$ 2,624	$ 2,016

	Three Months Ended September 30, 2001			Nine Months Ended September 30, 2001		
Total assets	$ 44,241	$ 19,458	$ 63,699	$ 44,241	$ 19,458	$ 63,699
Capital expenditures	$ 4,744	$ 1,122	$ 5,866	$ 12,022	$ 5,100	$ 17,122

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

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 September 30, 2002 and 2001 (third quarter) for the Company's United States and Canadian operations.

	United States Three Months Ended September 30,			Canada Three Months Ended September 30,		
	2002	2001	Change	2002	2001	Change
	(U.S. dollars in thousands, except prices and per Mcfe information)			(U.S. dollars in thousands, except prices and per Mcfe information)		
Revenues:						
Oil and gas revenues	$ 2,121	$ 1,985	7%	$ 1,536	$ 2,119	-28%
Marketing and other, net	88	(395)	-122%			n/a
Total revenues	$ 2,209	$ 1,590	39%	$ 1,536	$ 2,119	-28%
Daily production volumes:						
Natural gas (MMcf)	7.9	7.9	0%	5.2	6.2	-16%
Oil and liquids (Bbl)	265	227	17%	123	149	-17%
Equivalent production (MMcfe 6:1)	9.5	9.3	2%	5.9	7.1	-17%
Average price realized:						
Natural gas (Mcf)	$ 2.14	$ 2.01	6%	$ 2.69	$ 3.21	-16%
Oil and liquids (Bbl)	23.43	25.62	-9%	21.22	20.27	5%
Direct lifting costs	$ 444	$ 476	-7%	$ 490	$ 372	32%
Average direct lifting costs/Mcfe	0.51	0.56	-9%	0.89	0.57	56%
Other production costs	413	419	-1%			n/a
General and administrative, net	624	646	-3%	436	405	8%
Depreciation, depletion and amortization	686	901	-24%	542	663	-18%
Interest and other expense, net	222	164	35%	84	32	163%
Income tax provision (benefit)		(382)	-100%	57	317	-82%

Revenues from oil and gas sales of Carbon USA for the third quarter of 2002 were $2.1 million, a 7% increase from 2001. The increase was due primarily to increased oil production and increased natural gas prices. Natural gas production was approximately unchanged compared to the third quarter of 2001, despite the fact the Company voluntarily curtailed approximately 3% of its natural gas production due to low natural gas prices in the third quarter of 2002.

Revenues from oil, liquids and gas sales of CEC for the third quarter of 2002 were $1.5 million, a 28% decrease from 2001. The decrease was due primarily to decreased natural gas prices and a decrease in oil, liquids and natural gas production largely due to voluntarily curtailing approximately 29% of its natural gas production because of low natural gas prices in the third quarter of 2002.

Average production in the United States for the third quarter of 2002 was 265 barrels of oil and liquids per day and 7.9 million cubic feet (MMcf) of gas per day, an increase of 2% from the same period in 2001 on a Mcf equivalent (Mcfe) basis where one barrel of oil or liquids is equal to six Mcf of gas. The increase in oil, liquids and gas production was due to successful drilling activities conducted during 2001 in the Piceance and Permian Basins, partially offset by natural production declines and natural gas production that was voluntarily curtailed during the third quarter of 2002 in the Piceance and Uintah Basins due to low natural gas prices. Due to these low natural gas prices, the Company delayed the completion and pipeline connection of several newly drilled wells until the fourth quarter of 2002. During the third quarter of 2002, Carbon USA participated in the drilling of three gross (1.1

net) wells of which one gross (.1 net) was completed as an oil well, one gross (.8 net) was completed as a gas well and one gross (.2 net) was abandoned as a dry hole. During the third quarter of 2001, Carbon USA participated in the drilling of ten gross (7.0 net) wells of which three gross (2.1 net) wells were completed as oil wells and seven gross (4.9 net) wells were completed as gas wells.

Average production in Canada for the third quarter of 2002 was 123 barrels of oil and liquids per day and 5.2 MMcf of gas per day, a decrease of 17% on a Mcfe basis from the same period in 2001. The decrease was primarily due to natural production declines in all operating areas and natural gas and liquids production that was voluntarily curtailed during the third quarter of 2002 due to low natural gas prices. Due to these low natural gas prices, the Company delayed the completion and pipeline connection of several newly drilled wells until the fourth quarter of 2002. During the third quarter of 2002, CEC participated in the drilling of four gross (2.5 net) wells which were completed as gas wells. During the third quarter of 2001, CEC participated in the drilling of three gross (3.0 net) wells which were completed as gas wells.

Average oil and liquids prices realized by Carbon USA decreased 9% from $25.62 per barrel for the third quarter of 2001 to $23.43 for 2002. The average oil and liquids price includes hedge losses of $34,000 or $1.40 per barrel for the third quarter of 2002. There was no oil hedge activity for the third quarter of 2001. Average natural gas prices realized by Carbon USA increased 6% from $2.01 per Mcf for the third quarter of 2001 to $2.14 for 2002. The average natural gas price includes hedge gains of $308,000 or $.42 per Mcf for the third quarter of 2002 compared to hedge losses of $280,000 or $.39 per Mcf for 2001.

Average oil and liquids prices realized by CEC increased 5% from $20.27 per barrel for the third quarter of 2001 to $21.22 for 2002. The average oil and liquids price includes hedge losses of $9,000 or $.76 per barrel for the third quarter of 2002. There was no oil hedge activity for the third quarter of 2001. Average natural gas prices realized by CEC decreased 16% from $3.21 per Mcf for the third quarter of 2001 to $2.69 for 2002. The average natural gas price includes hedge gains of $118,000 or $.25 per Mcf for the third quarter of 2002 compared to hedge gains of $191,000 or $.33 Mcf for 2001.

Marketing and other revenues in the United States were $88,000 for the third quarter of 2002 compared to losses of $395,000 for 2001. For the third quarter of 2001, Carbon USA recorded a $625,000 impairment for an outstanding account receivable from a purchaser of the Company's gas production. This impairment was partially offset by mark-to-market gains of $158,000 related to a derivative contract that did not qualify for hedge accounting treatment under Statement of Financial Accounting Standard (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." In conjunction with the adoption of SFAS No. 133, the Company recorded a derivative loss (net of tax) of $1.5 million as the cumulative effect of a change in accounting principle related to the derivative contract.

Direct lifting costs incurred by Carbon USA were $444,000 or $.51 per Mcfe for the third quarter of 2002 compared to $476,000 or $.56 per Mcfe for 2001. The decrease in direct lifting costs was primarily due to a decrease in the number of well workovers and equipment repairs compared to the third quarter of 2001.

Other production costs incurred by Carbon USA, consisting primarily of severance taxes and production overhead, were $413,000 for the third quarter of 2002 compared to $419,000 for 2001.

Direct lifting costs incurred by CEC were $490,000 or $.89 per Mcfe for the third quarter of 2002 compared to $372,000 or $.57 per Mcfe for 2001. The higher per Mcfe expense in the third quarter of 2002 was primarily due to higher compression expenses associated with the production of natural gas in Alberta, the effect of fixed operating costs which were not reduced during the voluntary curtailment of production during the third quarter of 2002 and a small increase in ad valorem taxes.

General and administrative (G&A) expenses (net of overhead reimbursements on operated wells) incurred by Carbon USA decreased 3% from $646,000 for the third quarter of 2001 to $624,000 for 2002. For the third quarter of 2001 and 2002, 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 CEC increased 8% from $405,000 for the third quarter of 2001 to $436,000 for 2002. For the third quarter of 2001 and 2002, CEC did not capitalize any G&A related to geological and geophysical activities.

Interest and other expense incurred by Carbon USA increased 35% from $164,000 for the third quarter of 2001 to $222,000 for 2002. The increase was due primarily to increased average debt balances in the third quarter of 2002 relative to 2001, partially offset by a decline in interest rates.

Interest and other expense incurred by CEC increased 163% from $32,000 for the third quarter of 2001 to $84,000 for 2002. The increase was due primarily to increased average debt balances in the third quarter of 2002 relative to 2001, partially offset by a decline in interest rates.

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 CEC, the volume of proved reserves the Company acquired in the acquisitions and a ceiling test impairment recorded by the Company in June 2002.

DD&A expense incurred by Carbon USA was $686,000 or $.79 per Mcfe for the third quarter of 2002 compared to $901,000 or $1.06 per Mcfe for 2001. The decreased rate is primarily due to the ceiling test impairment recorded by the Company in the second quarter of 2002.

DD&A expense incurred by CEC was $542,000 or $.98 per Mcfe compared to $663,000 or $1.01 per Mcfe for 2001. The decreased rate is primarily due to the ceiling test impairment recorded by the Company in the second quarter of 2002.

No provision for income tax expense was recorded by Carbon USA for the third quarter of 2002 as the Company recorded a deferred tax asset valuation allowance of $68,000. This compared to an income tax benefit of $382,000 and an effective tax rate of 37% for the third quarter of 2001.

Income tax expense incurred by CEC was $57,000 for the third quarter of 2002, an effective tax rate of (356)%, compared to $317,000 and an effective tax rate of 49% for 2001. The effective tax rate for the third quarter of 2002 was due to permanent differences in the deductibility of Canadian royalties for oil, liquids, and natural gas versus a resource allowance, that was magnified due to the small ($16,000) loss before income taxes in the third quarter of 2002.

The following table and discussion present comparative revenue, production volumes, average sales prices, expenses and the percentage change between periods for the nine months ended September 30, 2002 and 2001 for the Company's United States and Canadian operations.

	United States Nine Months Ended September 30,			Canada Nine Months Ended September 30,		
	2002	**2001**	**Change**	**2002**	**2001**	**Change**
	(U.S. dollars in thousands, except prices and per Mcfe information)			(U.S. dollars in thousands, except prices and per Mcfe information)		
Revenues:						
Oil and gas revenues	$ 6,208	$ 8,255	-25%	$ 5,033	$ 9,216	-45%
Marketing and other, net	267	857	-69%			n/a
Total revenues	6,475	9,112	-29%	5,033	9,216	-45%
Daily production volumes:						
Natural gas (MMcf)	8.5	7.3	16%	5.9	6.6	-11%
Oil and liquids (Bbl)	251	227	11%	139	160	-13%
Equivalent production (MMcfe 6:1)	10.0	8.7	15%	6.7	7.6	-12%
Average price realized:						
Natural gas (Mcf)	$ 2.05	$ 3.30	-38%	$ 2.67	$ 4.54	-41%
Oil and liquids (Bbl)	21.55	27.11	-21%	18.75	24.45	-23%

	United States Nine Months Ended September 30,			Canada Nine Months Ended September 30,		
Direct lifting costs	$ 1,203	$ 1,256	-4%	$ 1,222	$ 1,168	5%
Average direct lifting costs/Mcfe	0.44	0.53	-17%	0.66	0.57	16%
Other production costs	1,251	1,458	-14%	82	14	486%
General and administrative, net	2,248	2,033	11%	1,302	1,332	-2%
Depreciation, depletion and amortization	2,802	2,442	15%	1,863	1,958	-5%
Full cost ceiling impairment	12,003		n/a	1,215		n/a
Interest and other expense, net	592	481	23%	166	150	11%
Income tax provision (benefit)	746	540	38%	(313)	1,970	-116%

Revenues from oil and gas sales of Carbon USA for the first nine months of 2002 were $6.2 million, a 25% decrease from 2001. The decrease was due primarily to decreased oil and natural gas prices, partially offset by increased oil, liquids and natural gas production.

Revenues from oil, liquids and gas sales of CEC for the first nine months of 2002 were $5.0 million, a 45% decrease from 2001. The decrease was due primarily to decreased oil, liquids and natural gas prices and a decrease in oil, liquids and natural gas production largely due to voluntary curtailing approximately 11% of its natural gas production because of low natural gas prices in the first nine months of 2002.

Average production in the United States for the first nine months of 2002 was 251 barrels of oil and liquids per day and 8.5 million cubic feet (MMcf) of gas per day, an increase of 15% from the same period in 2001 on a Mcf equivalent (Mcfe) basis where one barrel of oil or liquids is equal to six Mcf of gas. The increase in oil, liquids and gas production was due to successful drilling activities conducted during 2001 in the Piceance and Permian Basins, partially offset by natural production declines. Due to low natural gas prices in the Piceance and Uintah Basins, the Company delayed the completion and pipeline connection of several newly drilled wells until the fourth quarter of 2002. During the first nine months of 2002, Carbon USA participated in the drilling of six gross (1.3 net) wells of which four gross (.3 net) were completed as oil wells, one gross (.7 net) was completed as a gas well and one gross (.3 net) was abandoned as a dry hole. During the first nine months of 2001, Carbon USA participated in the drilling of 24 gross (14.7 net) wells of which seven gross (3.0 net) were

completed as oil wells, fifteen gross (10.2 net) were completed as gas wells and two gross (1.5 net) were abandoned as dry holes.

Average production in Canada for the first nine months of 2002 was 139 barrels of oil and liquids per day and 5.9 MMcf of gas per day, a decrease of 12% on a Mcfe basis from the same period in 2001. The decrease was primarily due to low natural gas prices and natural production declines in all operating areas and natural gas and liquids production that was voluntarily curtailed during the third quarter of 2002 due to low natural gas prices, partially offset by successful drilling activities in the Carbon and Rowley areas of Central Alberta. Due to low natural gas prices in Central Alberta, the Company delayed the completion and pipeline connection of several newly drilled wells until the fourth quarter of 2002. During the first nine months of 2002, CEC participated in the drilling of eleven gross (7.2 net) wells of which ten gross (6.7 net) were completed as gas wells and one gross (.5 net) was abandoned as a dry hole. During the first nine months of 2001, CEC participated in the drilling of seven gross (7.0 net) wells which were completed as gas wells.

Average oil and liquids prices realized by Carbon USA decreased 21% from $27.11 per barrel for the first nine months of 2001 to $21.55 for 2002. The average oil and liquids price includes hedge losses of $50,000 or $.73 per barrel for the first nine months of 2002. There was no oil hedge activity for the first nine months of 2001. Average natural gas prices realized by Carbon USA decreased 38% from $3.30 per Mcf for the first nine months of 2001 to $2.05 for 2002. The average natural gas price includes hedge gains of $373,000 or $.16 per Mcf for the first nine months of 2002 compared to hedge losses of $1.6 million or $.79 per Mcf for 2001.

Average oil and liquids prices realized by CEC decreased 23% from $24.45 per barrel for the first nine months of 2001 to $18.75 for 2002. The average oil price includes hedge gains of $2,000 or $.05 per barrel for the first nine months of 2002. There was no oil hedge activity for the first nine months of 2001. Average natural gas prices realized by CEC decreased 41% from $4.54 per Mcf for the first nine months of 2001 to $2.67 for 2002. The average natural gas price includes hedge gains of $134,000 or $.08 per Mcf for the first nine months of 2002 compared to hedge losses of $730,000 or $.40 per Mcf for 2001.

Marketing and other revenues in the United States were $267,000 for the first nine months of 2002 compared to $857,000 for 2001. Marketing revenue for the first nine months of 2001 included mark-to-market gains of $1.2 million related to a derivative contract that did not qualify for hedge accounting treatment under Statement of Financial Accounting Standard (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." In conjunction with the adoption of SFAS No. 133, the Company recorded a derivative loss (net of tax) of $1.5 million as the cumulative effect of a change in accounting principle related to the derivative contract. Marketing and other revenues in 2001 also included a $625,000 impairment recorded in the third quarter of 2001 for an outstanding account receivable from a purchaser of the Company's gas production.

Direct lifting costs incurred by Carbon USA were $1.2 million or $.44 per Mcfe for the first nine months of 2002 compared to $1.3 million or $.53 per Mcfe for 2001. The decrease in direct lifting costs was primarily due to a decrease in the number of well workovers and equipment repairs compared to the first nine months of 2001.

Other production costs incurred by Carbon USA, consisting primarily of severance taxes and production overhead, were $1.3 million for the first nine months of 2002 compared to $1.5 million for 2001. The decrease was primarily due to lower severance taxes as a result of lower oil, liquids and gas prices and a credit for prior period ad valorem taxes, partially offset by increased oil, liquids and gas production.

Direct lifting costs incurred by CEC were $1.2 million or $.66 per Mcfe for the first nine months of 2002 compared to $1.2 million or $.57 per Mcfe for 2001. The higher per Mcfe expense for the first

nine months of 2002 was primarily due to compression expenses associated with the production of natural gas in Alberta, the effect of fixed operating costs which were not reduced during the voluntary curtailment of production during the third quarter of 2002 and a small increase in ad valorem taxes.

Other production costs incurred by CEC, consisting primarily of severance taxes, were $82,000 for the first nine months of 2002 compared to $14,000 for 2001. The increase was primarily due to increased production during the first nine months of 2002 from wells subject to severance taxes.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by Carbon USA increased 11% from $2.0 million for the first nine months of 2001 to $2.2 million for 2002. The increase was primarily due to one time legal expenses of $160,000. For the first nine months of 2001 and 2002, Carbon USA capitalized $155,000 and $122,000, respectively, of G&A related to geological and geophysical activities.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by CEC were $1.3 for the first nine months of 2001 and 2002. For the first nine months of 2001 and 2002, CEC did not capitalize any G&A related to geological and geophysical activities.

Interest and other expense incurred by Carbon USA increased 23% from $481,000 for the first nine months of 2001 to $592,000 for 2002. The increase was due primarily to increased average debt balances in the first nine months of 2002 relative to 2001, partially offset by a decline in interest rates.

Interest and other expense incurred by CEC increased 11% from $150,000 for the first nine months of 2001 to $166,000 for 2002. The increase was due primarily to increased average debt balances in the first nine months of 2002 relative to 2001, partially offset by a decline in interest rates.

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 CEC, 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 $2.8 million or $1.03 per Mcfe for the first nine months of 2002 compared to $2.4 million or $1.03 per Mcfe for 2001. An increase in the DD&A rate per Mcfe as a result of the capitalized cost per Mcfe of reserves added to the Company's proved reserves in 2001 was offset by a reduction in the DD&A rate due to a ceiling test impairment recorded by the Company in the second quarter of 2002, resulting in a DD&A rate per Mcfe which was identical to 2001.

DD&A expense incurred by CEC was $1.9 million or $1.01 per Mcfe for the first nine months of 2002 compared to $2.0 million or $.95 per Mcfe for 2001. The increased rate for the first nine months of 2002 compared to 2001 is due to the capitalized cost per Mcfe of reserves added to the Company's proved reserves during 2001, partially offset by a ceiling test impairment recorded by the Company in the second quarter of 2002.

The non-cash ceiling test impairment of the Company's full cost pool was recorded 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 the quarterly reporting period. Under the SEC guidelines, the natural gas and oil prices used to determine the future value of the Company's oil and gas reserves is the market price in effect on the last day of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements). The SEC allows the use of hedge adjusted prices in the full cost ceiling test and the Company's ceiling test was reflective of that methodology.

At June 30, 2002, the methodology required the Company to use natural gas prices of $1.10/MMBtu in Colorado and Utah and $1.43/MMBtu in Central Alberta, prices which were $2.32/MMBtu for Colorado and Utah and $1.99/MMBtu for Alberta less, respectively, 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 of $.37/MMBtu for Colorado and Utah and $.29/MMBtu for Alberta at June 30, 2002. 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 the 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.

During the third quarter of 2002, natural gas prices received by Carbon for production in Colorado and Utah averaged approximately $1.41 per MMBtu, approximately $1.75 per MMBtu less than the price posted for natural gas delivered to Henry Hub. Approximately 60% of the Company's United States production is situated in Colorado and Utah. During the second and third quarters of 2002, natural gas prices for production in these areas were unusually low relative to the rest of the producing areas in the United States. Lack of regional seasonal demand and inadequate pipeline transportation capacity necessary to transport natural gas to consuming regions are principal factors contributing to the large price differentials. The prospect of increased winter demand for natural gas and the prospect of additional pipeline capacity out of the region are expected to help alleviate the high price differentials received by Carbon and other Rocky Mountain gas producers. However, continued volatility is expected to affect the price received for natural gas produced by Carbon in the United States and Canada.

Income tax expense recorded by Carbon USA was $746,000 for the first nine months of 2002, compared to $540,000 and an effective tax rate of 38% for 2001. 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 $5.8 million during the first nine months of 2002.

Income tax benefit reported by CEC was $313,000 for the first nine months of 2002, an effective tax rate of 38%, compared to an expense of $2.0 million and an effective tax rate of 43% for 2001. The decrease in the effective tax rate was due to an adjustment of deferred taxes related to a change in the statutory tax rates. The income tax benefit related to the above mentioned full cost ceiling impairment was $517,000.

Liquidity and Capital Resources

At September 30, 2002, the Company had $49.6 million of assets. Total capitalization was $40.6 million, consisting of 45% of stockholders' equity and 55% of debt.

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

For the nine months ended September 30, 2002, net cash provided by operations was $1.3 million compared to $10.7 in 2001. Net cash provided by operations prior to changes in working capital for the nine months ended September 30, 2002 was $3.4 million compared to $7.2 million in 2001. The decrease in operating cash flow was primarily due to declines in oil, liquids, and natural gas prices in all regions, partially offset by increased oil, liquids and natural gas production in the United States.

For the nine months ended September 30, 2002, net cash used in investing activities was $5.9 million compared to $11.1 million in 2001. For the nine months ended September 30, 2002, net cash provided by financing activities was $4.6 million compared to $429,000 in 2001. For the nine months ended September 30, 2002, the Company spent approximately $3.7 million in the United States primarily to fund development and exploration activities in Colorado, Montana, New Mexico and Utah. The Company received $2.7 million in proceeds related to the disposition of certain overriding royalty interests in the Piceance and Permian Basins and the sale of working interest and related leasehold rights in Kansas. For the nine months ended September 30, 2002, the Company spent approximately $4.9 million in Canada primarily to fund development and exploration activities in the Carbon area and for the acquisition of properties in the Rowley area of Central Alberta. For the nine months ended September 30, 2001, the Company spent approximately $12.0 million in the United States primarily to fund development and exploration activities in Colorado, New Mexico and Utah. The Company received $6.8 million in proceeds related to the disposition of the Company's working interest and related leasehold rights in the San Juan Basin. For the nine months ended September 30, 2001, the Company spent approximately $5.1 million primarily to fund development activities in the Carbon area of Central Alberta.

Carbon's primary cash requirements will be to fund exploration and development expenditures, finance acquisitions, repay debt, and for general working capital needs. At September 30, 2002, the Company had no cash balances as all available cash flow generated from operations was used to pay down the Company's long-term debt and working capital deficit. The Company anticipates that capital expenditures for the fourth quarter of 2002, exclusive of unplanned acquisitions or divestitures will be approximately $4.0 million. At September 30, 2002, the Company is in compliance with all of 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 September 30, 2002 were approximately $4.7 million, although the U.S. facility is subject to a borrowing base reduction of $400,000 per month through January 1, 2003. Carbon believes, however, 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.

In October 2002, Carbon announced its intent to exit completely the Permian Basin region. The Company has an interest in 98 gross (23 net) wells and 26,311 gross (8,635 net) acres located primarily in Southeast New Mexico. At September 30, 2002, daily average net production from the properties was approximately 3,270 Mcf of gas per day and 130 barrels of oil per day. The Company expects to use the proceeds from the planned asset sale to continue its exploration and development drilling program in the Piceance and the 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 September 30, 2002 and the effect such obligations are expected to have on its liquidity and cash flow in future periods (in thousands):

	Payments Due By Period		
Contractual Obligations	**Less than 1 Year**	**1-3 Years**	**4-5 Years**
Revolving credit facilities	$	$ 7,271	$ 8,078
Operating leases / management agreements, net	403	328	
	$ 403	$ 7,599	$ 8,078

Certain Factors That May Affect Future Results

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 2001 Form 10-K 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.

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.

Use of Estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

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. The estimated future cost of site restoration, dismantlement and abandonment activities is 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, total 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 un-escalated 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.

The non-cash ceiling test impairment of the Company's full cost pool was recorded 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 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 the quarterly reporting period. Under the SEC guidelines, the natural gas and oil prices used to determine the future value of the Company's oil and gas reserves is the market price in effect on the last day of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements).

At June 30, 2002, the methodology required the Company to use natural gas prices of $1.10/MMBtu in Colorado and Utah and $1.43/MMBtu in Central Alberta, prices which were $2.32/MMBtu for Colorado and Utah and $1.99/MMBtu for Alberta less, respectively, 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 of $.37/MMBtu for Colorado and Utah and $.29/MMBtu for Alberta at June 30, 2002. 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 the 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.

Due to the volatility of commodity prices, should natural gas and crude oil prices decline in the future, even if only for a brief period of time, it is possible that additional impairments of oil and gas properties could occur.

Derivative Instrument and Hedging Activities Pursuant to Company guidelines, the Company is to engage in these activities only as a hedging mechanism and may not enter into speculative transactions. The Company has a Risk Management Committee to administer and approve all hedging 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. Gains or losses from financial instruments that do not qualify for hedge accounting treatment are recognized currently as other income or expense. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flows.

The Company follows SFAS No. 133, which provides accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. It also requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

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 September 30, 2002, the Company had $16.2 million of floating rate debt through its facility with Wells Fargo and $6.3 million through its facility with CIBC. In addition, the Company currently has interest rate swap agreements that effectively convert a portion of its variable rate borrowings to fixed rate debt as described in Note 2 to the Consolidated Financial Statements in this report. Assuming constant debt levels, the impact on earnings and cash flow for the twelve month period beginning October 1, 2002, from a one percent change in interest rates would be approximately $140,000 before taxes.

Foreign Currency Risk

The Canadian dollar is the functional currency of CEC. 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 investments 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 for the Company's natural gas production may not be an accurate indication of the market price for natural gas.

Approximately 60% of the Company's United States production is situated in Colorado and Utah. During the second and third quarters of 2002, natural gas prices for production in these areas were unusually low relative to the rest of the producing areas in the United States. Lack of regional seasonal demand and inadequate pipeline transportation capacity necessary to transport natural gas to consuming regions are principal factors contributing to the large price differentials. The prospect of increased winter demand for natural gas and the prospect of additional pipeline capacity out of the region are expected to help alleviate the high price differentials received by Carbon and other Rocky Mountain gas producers. However, 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 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 included counterparty credit risk, Carbon's inability to deliver required physical volumes of gas which support the Company's hedges, inefficient or non-correlatable hedges, basis risk, inability to liquidate hedge positions if desired and other unforeseen economic factors. For additional information, see Note 2 to the Consolidated Financial Statements in this report. In addition, quantitative and qualitative disclosures about market risk are included in the Company's Form 10-K (Item 7A) and the financial statements included therein for the fiscal year ended December 31, 2001.

Item 4. CONTROLS AND PROCEDURES

Within the 90 days prior to the date of this report, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including Carbon's principal executive officer and principal financial officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rule 13a-14 under the Securities Exchange Act of 1934. Based upon that evaluation, the principal executive officer and principal financial officer concluded that the Company's disclosure controls and procedures are effective for purposes of recording, summarizing and timely reporting material information required to be disclosed in reports that the Company files under the Securities Exchange Act of 1934. There were no significant changes in the Company's internal controls or in other factors that could significantly affect these controls since the date the controls were evaluated.

PART II OTHER INFORMATION

Item 1-5 Not applicable.

Item 6 (a) Exhibits

10.1 First Amendment of Amended and Restated Credit Agreement between Carbon Energy Corporation (USA) and Wells Fargo Bank, N.A.*

99.1 Certification of 10-Q Report, dated November 13, 2002, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

(b) No reports on Form 8-K were filed by the registrant during the quarter ended September 30, 2002.

* Filed 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: November 14, 2002 By: /s/ PATRICK R. MCDONALD

President and Chief Executive Officer

Date: November 14, 2002 By: /s/ KEVIN D. STRUZESKI

Treasurer and Chief Financial Officer

CERTIFICATION

I, Patrick R. McDonald certify that:

1. I have reviewed this quarterly report on Form 10-Q of Carbon Energy Corporation;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3.

Based on my knowledge, the financial statements and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

(a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

(b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

(c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors and material weaknesses in internal controls; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 14, 2002

By: /s/ PATRICK R. MCDONALD

Patrick R. McDonald
President and Chief Executive Officer

CERTIFICATION

I, Kevin D. Struzeski certify that:

1. I have reviewed this quarterly report on Form 10-Q of Carbon Energy Corporation;

2. Based on my knowledge, this quarterly report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this quarterly report;

3. Based on my knowledge, the financial statements and other financial information included in this quarterly report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this quarterly report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

   (a) designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this quarterly report is being prepared;

   (b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

   (c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

   (a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors and material weaknesses in internal controls; and

   (b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 14, 2002

By: /s/ KEVIN D. STRUZESKI

Kevin D. Struzeski
Chief Financial Officer