CARBON ENERGY CORP
Form 10-Q
November 14, 2001

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2001

Or

/ / **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 /x/ No / /

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 9, 2001

Common stock, no par value	6,105,425 shares

CARBON ENERGY CORPORATION

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CARBON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
(in thousands)

	September 30, 2001	December 31, 2000
	(unaudited)	
ASSETS		
Current assets:		
Cash	$	$ 21
Current portion of employee trust	644	683
Accounts receivable, trade	3,794	6,129
Accounts receivable, other	168	337
Amounts due from broker	78	3,871
Prepaid expenses and other	388	701
Current derivative asset	586	

	September 30, 2001	December 31, 2000
Total current assets	5,658	11,742
Property and equipment, at cost:		
Oil and gas properties, using the full cost method of accounting:		
Unproved properties	8,300	6,576
Proved properties	57,861	49,547
Furniture and equipment	920	398
	67,081	56,521
Less accumulated depreciation, depletion and amortization	(10,426)	(6,152)
Property and equipment, net	56,655	50,369
Other long term assets:		
Deposits and other assets	1,349	369
Long term derivative asset	37	
Total other long term assets	1,386	369
Total assets	$ 63,699	$ 62,480

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

CONSOLIDATED BALANCE SHEETS
(in thousands except share data)

	September 30, 2001	December 31, 2000
	(unaudited)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 6,934	$ 9,583
Accrued production taxes payable	580	637
Income taxes payable	1,403	228
Undistributed revenue	1,177	1,561
Current derivative liability	13	
Deferred income taxes	85	
Total current liabilities	10,192	12,009
Long-term debt	15,229	15,082
Deferred income taxes	3,836	2,984
Minority interest	28	170
Stockholders' equity:		
Preferred stock, no par value:		
10,000,000 shares authorized, none outstanding		

	September 30, 2001	December 31, 2000
Common stock, no par value:		
20,000,000 shares authorized, issued, and 6,074,100 shares and 6,021,626 shares outstanding at September 30, 2001 and December 31, 2000, respectively	31,771	31,495
Retained earnings	2,981	965
Accumulated other comprehensive loss	(338)	(225)
Total stockholders' equity	34,414	32,235
Total liabilities and stockholders' equity	$ 63,699	$ 62,480

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)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2001	2000	2001	2000
	(unaudited)			
Revenues:				
Oil and gas sales	$ 4,696	$ 4,384	$ 19,815	$ 11,413
Marketing and other, net	(395)	(21)	857	86
	4,301	4,363	20,672	11,499
Expenses:				
Oil and gas production costs	1,859	1,578	6,240	3,826
Depreciation, depletion and amortization	1,564	1,517	4,400	4,034
General and administrative, net	1,051	748	3,365	2,054
Interest, net	195	323	605	783
Total operating expenses	4,669	4,166	14,610	10,697
Minority interest	1	4	26	11
Income (loss) before income taxes	(369)	193	6,036	791
Income tax provision (benefit):				
Current	184	75	1,672	240
Deferred	(249)	(54)	838	31
Total taxes	(65)	21	2,510	271
Net income (loss) before cumulative effect of change in accounting principle	(304)	172	3,526	520

	Three Months Ended September 30,		Nine Months Ended September 30,	
Cumulative effect of change in accounting principle, net of tax			(1,510)	
Net income (loss)	$ (304)	$ 172	$ 2,016	$ 520
Average number of common shares outstanding:				
Basic	6,070	6,015	6,048	5,755
Diluted	6,070	6,075	6,291	5,801
Earnings (loss) per share basic:				
Net income (loss) before cumulative effect of change in accounting principle	$ (0.05)	$ 0.03	$ 0.58	$ 0.09
Cumulative effect of change in accounting principle, net of tax			(0.25)	
	$ (0.05)	$ 0.03	$ 0.33	$ 0.09
Earnings (loss) per share diluted:				
Net income (loss) before cumulative effect of change in accounting principle	$ (0.05)	$ 0.03	$ 0.56	$ 0.09
Cumulative effect of change in accounting principle, net of tax			(0.24)	
	$ (0.05)	$ 0.03	$ 0.32	$ 0.09

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

CARBON ENERGY CORPORATION

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
For the Nine Months Ended September 30, 2001
(in thousands)
(unaudited)

	Common Stock				
	Shares	Amount	Retained Earnings	Other Comprehensive Income (Loss)	Total
Balances, December 31, 2000	6,022	$ 31,495	$ 965	$ (225)	$ 32,235
Comprehensive income:					
Net income before cumulative effect of change in accounting principle			3,526		3,526
Cumulative effect of change in accounting principle, net of tax			(1,510)	(2,768)	(4,278)
Currency translation adjustment				(440)	(440)
Reclassification adjustment for settled contracts				1,381	1,381

	Common Stock				
Changes in fair value of outstanding hedge positions				1,714	1,714
Total comprehensive income					1,903
Common stock issued, net of treasury stock	35	180			180
Vesting of restricted stock grants	17	96			96
Balances, September 30, 2001	6,074	$ 31,771	$ 2,981	$ (338)	$ 34,414

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

CARBON ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Nine Months Ended September 30,	
	2001	**2000**
	(unaudited)	
Cash flows from operating activities:		
Net income	$ 2,016	$ 520
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization expense	4,400	4,034
Change in fair market value of derivatives	(1,713)	
Deferred income tax	838	31
Cumulative effect of change in accounting principle	1,510	
Minority interest	26	11
Vesting of restricted stock grants	96	87
Changes in operating assets and liabilities net of effects of acquisition:		
Decrease (increase) in:		
Accounts receivable	2,994	(350)
Amounts due from broker	3,793	(2,062)
Employee trust	39	826
Prepaid expenses and other assets	927	(718)
Increase (decrease) in:		
Accounts payable and accrued expenses	(3,902)	(1,846)
Undistributed revenue	(341)	552

	Nine Months Ended September 30,	
Net cash provided by operating activities	10,683	1,085
Cash flows from investing activities:		
Capital expenditures for oil and gas properties	(17,122)	(6,397)
Cash received from San Juan property sale	6,758	
Acquisition of CEC Resources		(146)
Capital expenditures for support equipment	(521)	(121)
Net cash used in investing activities	(10,885)	(6,664)
Cash flows from financing activities:		
Proceeds from notes payable	39,719	23,621
Principal payments on notes payable	(39,470)	(18,563)
Proceeds from issuance of common stock	180	55
CEC share repurchase	(203)	
Net cash provided by financing activities	226	5,113
Effect of exchange rate changes on cash	(45)	
Net decrease in cash	(21)	(466)
Cash, beginning of period	21	995
Cash, end of period	$	$ 529
Supplemental cash flow information:		
Cash paid for interest	$ 743	$ 1,017
Cash paid for taxes	461	46

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 Operation Carbon Energy Corporation (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. Over 97% of the shareholders of CEC accepted the offer to exchange. The offer to exchange closed on February 17, 2000 and was accounted for as a purchase. In November 2000, CEC initiated an offer to purchase shares of CEC 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 CEC stock that were not owned by Carbon. Carbon currently owns 99.7% of the stock of CEC. Collectively, Carbon, CEC, BFC and its subsidiaries are referred to as the Company. 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 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 Texas and the Hugoton Basin in Southwest

Kansas. The Company's exploration and production areas in Canada include Central Alberta and Southeast Saskatchewan.

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 generally accepted accounting principles 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, 2000, as filed with the SEC. The statements reflect all adjustments which, in the opinion of management, are necessary to fairly present the Company's financial position at September 30, 2001 and the results of operations and cash flows for the periods presented.

All amounts are presented in U.S. dollars unless otherwise stated.

2. Significant Accounting Principles:

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% of the equity. 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.

Amounts Due From Broker This account represents net cash margin deposits held by a brokerage firm for the Company's derivative accounts.

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 on a country-by-country basis and are depleted using the units of production method based on proved reserves of oil and gas. The Company presently has two cost centers the United States and Canada. For purposes of the depletion calculation, oil and gas reserves are converted to a common unit of measure on the basis of six thousand cubic feet of gas to one barrel of oil. A reserve is provided for the estimated future cost of site restoration, dismantlement and abandonment activities 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 oil and gas reserves.

Pursuant to full cost accounting rules, capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of (1) 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 (2) the cost of properties not being amortized, if any; plus (3) the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less (4) related income tax effects. At September 30, 2001 the "spot" prices that the Company would have realized for its natural gas and oil sales were at a level whereby the Company's capitalized costs in the United States and Canada exceeded the above limit by approximately $15.0 million. Subsequent to September 30, 2000 and before the release of these interim financial statements, the "spot" prices have rebounded, which has resulted in the present value of the Company's future net revenues, discounted at 10%, once again exceeding the Company's capitalized costs. Accordingly, we were not required to record a write down of properties. A decline in gas and oil prices from current levels, or other factors, without other mitigating circumstances, could cause a future write-down of capitalized costs and a non-cash charge against future earnings.

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 adjustment 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.

Employee Trust The employee trust represents amounts which may be used to satisfy obligations to persons who have been, or will be, terminated as a result of the Company's acquisition of BFC. The employee trust is expected to be disbursed or returned to the Company by October 31, 2001.

Undistributed Revenue Represents amounts due to other owners of jointly owned oil and gas properties for their share of revenue from the properties.

Revenue Recognition The Company follows the sales method of accounting for natural gas revenues. Under this method, revenues are recognized based on actual volumes of gas sold to purchasers. The volumes of gas sold may differ from the volumes to which the Company is entitled based on its interests in the properties, creating gas imbalances. Revenue is deferred and a liability is recorded for those properties where the estimated remaining reserves will not be sufficient to enable the underproduced owner to recoup its entitled share through production.

The Company records sales and the related cost of sales on gas marketing transactions using the accrual method of accounting (i.e., the transaction is recorded when the commodity is purchased and/or delivered).

The Company's gas marketing contracts are generally month-to-month and provide that the Company will sell to end users gas which is produced from the Company's properties and/or acquired from third parties.

Income Taxes The Company accounts for income taxes under 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 financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

Hedging Transactions The Company from time to time may use certain financial instruments in an attempt to reduce exposure to the market fluctuations in the price of oil and natural gas. The Company may hedge price risk of a portion of the Company's production with swap, collar, futures, and floor and ceiling arrangements. Pursuant to Company guidelines, the Company is to engage in these activities only as a hedging mechanism. The Company has a Risk Management Committee to administer its production hedging program 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 when the transactions being hedged are finalized. 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 these instruments are included in operating activities in the consolidated statements of cash flows.

The Company follows Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" which provides accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on 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. SFAS No. 133 became effective for the Company on January 1, 2001.

The table below sets forth the financial statement impact to the Company of recording derivative instruments designated as hedges and derivative instruments not designated as hedges upon the adoption of SFAS No. 133 on January 1, 2001.

		Amount (millions)
Balance Sheet:		
Derivative liability	$	(7.2)
Deferred tax asset		2.9
Cumulative effect of a change in accounting principle (other comprehensive loss)		2.8
Statement of Operations:		
Cumulative effect of a change in accounting principle (derivative loss)	$	1.5

During the first nine months of 2001, net hedging losses of $2.3 million ($1.4 million after tax) were transferred from other comprehensive income and the change in the fair market value of outstanding derivative liabilities for contracts designated as hedges decreased by $3.0 million ($1.7 million after tax). As of September 30, 2001, the Company had net unrealized derivative gains of $610,000 ($327,000 after tax). The Company expects to reclassify $573,000 of these gains to earnings during the next twelve month period.

The table below sets forth BFC's and CEC's derivative financial instrument positions that qualify for hedge accounting treatment as of September 30, 2001.

Futures and swaps:

BFC Contracts				**CEC Contracts**			
Year	**Bbl/ MMBtu**	**Weighted Average Fixed Price**	**Derivative Asset/ (Liability)**	**Year**	**Bbl/ MMBtu**	**Weighted Average Fixed Price**	**Derivative Asset/ (Liability)**

	BFC Contracts				CEC Contracts		
	Bbl/ MMBtu		(thousands)		Bbl/ MMBtu		(thousands)
Gas				**Gas**			
2001	80,000	$ 2.28	$ 10	2001	40,000	$ 2.21	$ 22

Collars:

BFC Contracts					CEC Contracts				
Year	Bbl/ MMBtu	Average Floor Bbl/ MMBtu	Average Ceiling Bbl/ MMBtu	Derivative Asset/ (Liability) (thousands)	Year	Bbl/ MMBtu	Average Floor Bbl/ MMBtu	Average Ceiling Bbl/ MMBtu	Derivative Asset/ (Liability) (thousands)
Oil					**Oil**				
2001	18,400	$ 24.00	$ 29.10	$ 27	2001	9,200	$ 24.00	$ 29.05	$ 13
2002	73,000	$ 22.00	$ 27.50	$ 46	2002	36,500	$ 22.00	$ 27.50	$ 25
Gas					**Gas**				
2001	123,000	$ 2.62	$ 3.37	$ 92	2001	117,000	$ 2.84	$ 3.84	$ 202
2002	304,000	$ 2.50	$ 3.50	$ 37	2002	288,000	$ 2.42	$ 3.42	$ 83

With the adoption of SFAS No. 133, the Company has a derivative contract that no longer qualifies for hedge accounting treatment. The table below sets forth the position of this contract as of September 30, 2001.

Swaps:

BFC Contracts			
Year	Bbl/ MMBtu	Weighted Average Fixed Price Bbl/ MMBtu	Derivative Asset/ (Liability) (thousands)
Gas			
2001	62,000	$ 2.04	$ 43

During the first nine months of 2001, payments of $1.4 million were made to the counterparty of this contract. The fair market value of this contract increased by $1.2 million and was recognized as other income.

During the first nine months of 2001, the Company entered into Permian Basin basis swaps that do not qualify for hedge accounting treatment. The value of these contracts were $8,000 at September 30, 2001. At September 30, 2001, basis swaps covering 40,000 MMBtu were outstanding and expire on or before October 31, 2001.

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 its functional currency, except for CEC, which uses the Canadian dollar. Assets and liabilities related to the operations of CEC are generally translated at current exchange rates, and the related translation adjustments are reported as a component of accumulated other comprehensive income in the statement of stockholders' equity. Income statement accounts are translated at the average rates during the period. As a result of the change in the value of the Canadian dollar relative to the U.S. dollar, the Company reported a non cash currency translation loss of $440,000 for the nine months ended September 30, 2001.

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 shareholders' equity and classified as other comprehensive income. The following table sets forth the calculation of comprehensive income for the nine months ended September 30, 2001 and 2000.

	Nine Months Ended September 30,	
	2001	2000

	Nine Months Ended September 30,	
	(in thousands)	
Net income	$ 2,016	$ 520
Other comprehensive income (loss), net of tax:		
Currency translation adjustment	(440)	42
Cumulative effect of change in accounting principle January 1, 2001	(2,768)	
Reclassification adjustment for settled contracts	1,381	
Changes in fair value of outstanding hedge positions	1,714	
Other comprehensive income (loss)	(113)	42
Comprehensive income	$ 1,903	$ 562

Earnings (Loss) Per Share The Company uses the weighted average number of shares outstanding in calculating 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.

3. Acquisition and Disposition of Assets:

Acquisition of CEC Resources Ltd. On February 17, 2000, Carbon completed the acquisition of approximately 97% of the stock of CEC. An offer to exchange shares of Carbon stock for shares of CEC stock resulted in the issuance of 1,482,826 shares of Carbon stock to holders of CEC stock. The acquisition was accounted for as a purchase. As stated in Note 1 to the financial statements, in February 2001, CEC acquired approximately 34,000 of the 39,000 remaining shares of CEC stock that were not owned by Carbon. Carbon currently owns 99.7% of the stock of CEC.

The following unaudited pro forma information presents a summary of the consolidated results of operations as if the acquisition had occurred at January 1, 2000.

	Nine Months Ended September 30, 2000
	(unaudited)
Total revenue	$ 12,149,000
Net income	$ 613,000
Earnings per share:	
Basic	$ 0.11
Diluted	$ 0.11

These unaudited pro forma results have been prepared for comparative purposes only and do not purport to be indicative of results of operations that actually would have resulted had the combination occurred at January 1, 2000, or future results of operations of the consolidated entities.

Disposition of Oil and Gas Assets In January 2001, the Company closed the sale of its entire working interest and related leasehold rights in the San Juan Basin, receiving net proceeds of approximately $6.8 million. The proceeds were used to repay amounts outstanding under the Company's credit facilities and to finance the Company's exploration and development program.

4. Long-Term Debt:

United States Facility The Company moved its credit facility from U.S. Bank National Association to Wells Fargo Bank West, National Association in the third quarter of 2000.

The facility is an oil and gas reserve based line-of-credit and had a borrowing base of $16.3 million with outstanding borrowings of $13.5 million at September 30, 2001. The borrowing base is subject to a $500,000 per month reduction schedule through November 1, 2001, at which time the borrowing base will be $15.3 million. The facility is secured by certain U.S. oil and gas properties of the Company and is scheduled to convert to a term note on October 1, 2002. This facility is scheduled to have a maturity date of either the economic half life of the Company's remaining U.S. reserves on the last day of the revolving period, or October 1, 2006, whichever is earlier. The facility bears interest at a rate equal to LIBOR plus 1.75% or Wells Fargo Bank West Prime, at the option of the Company. The Company's average borrowing rate was approximately 5.4% at September 30, 2001. The borrowing base is based upon the lender's semi-annual evaluation of the Company's proved oil and gas reserves.

The credit agreement contains 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 is also required to maintain certain financial ratios.

Canadian Facility In June 2001, the Company secured an increase to approximately $9.2 million from approximately $4.3 million in the borrowing base of its facility with the Canadian Imperial Bank of Commerce (CIBC). Outstanding borrowings against the facility were $1.7 million at September 30, 2001. 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, 2002. 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 any principal payments under the term loan section of the facility until October 2002 at the earliest. As such, no amounts under the Canadian facility have been classified as current on the September 30, 2001 balance sheet. The Canadian facility bears interest at the CIBC Prime rate plus 0.5%. The rate was approximately 5.75% at September 30, 2001.

The Canadian facility contains various covenants which limit the Company's ability to pay dividends, purchase treasury shares, incur indebtedness, sell properties, or merge with another entity.

The agreement with CIBC also provides for $3.5 million of credit which can be utilized for commodity swaps covering a portion of the Company's oil and gas production, forward exchange

contracts and gas purchase and sales transactions. The Company currently utilizes the swap facility to hedge a portion of its Canadian production (see Note 2).

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 and geographic segments: BFC and CEC, representing oil and gas operations in the United States and Canada, respectively. The segments are strategic business units which operate in unique geographic locations. The segment data presented below was prepared on the same basis as Carbon's consolidated financial statements.

	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	$ 2,711	$ 4,696	$ 8,255	$ 11,560	$ 19,815
Marketing and other, net	(395)		(395)	857		857
	1,590	2,711	4,301	9,112	11,560	20,672
Expenses:						
Oil and gas production costs	895	964	1,859	2,714	3,526	6,240
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, net	164	31	195	481	124	605
Total operating expenses	2,606	2,063	4,669	7,670	6,940	14,610
Minority interest		1	1		26	26

	Three Months Ended September 30, 2001			Nine Months Ended September 30, 2001		
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
Net 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
Total assets	$ 44,241	$ 19,458	$ 63,699	$ 44,241	$ 19,458	$ 63,699

	Three Months Ended September 30, 2000			Nine Months Ended Sep 30, 2000	Feb. 18 Through Sep 30, 2000	
	United States	Canada	Total	United States	Canada	Total
Revenues:						
Oil and gas sales	$ 2,785	$ 1,599	$ 4,384	$ 7,464	$ 3,949	$ 11,413
Marketing and other, net	50	(71)	(21)	157	(71)	86
	2,835	1,528	4,363	7,621	3,878	11,499
Expenses:						
Oil and gas production costs	1,024	554	1,578	2,640	1,186	3,826
Depreciation, depletion and amortization	1,079	438	1,517	2,929	1,105	4,034
General and administrative, net	452	296	748	1,323	731	2,054
Interest, net	270	53	323	652	131	783
Total operating expenses	2,825	1,341	4,166	7,544	3,153	10,697
Minority interest		4	4		11	11
Income before income taxes	10	183	193	77	714	791
Income tax provision		21	21		271	271
Net income	$ 10	$ 162	$ 172	$ 77	$ 443	$ 520
Total assets	$ 41,591	$ 14,732	$ 56,323	$ 41,591	$ 14,732	$ 56,323

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

Results of Operations

The following table and the discussion that follows present comparative revenue, sales, volumes, average sales prices, expenses and the percentage change between periods for the three months ended September 30, 2001 and 2000 (third quarter) for the Company's United States operations, conducted through BFC and the Company's Canadian operations, conducted through CEC.

	United States Three Months Ended September 30,			Canada (1) Three Months Ended September 30,		
	2001	2000	Change	2001	2000	Change
	(Dollars in thousands, except prices and per Mcfe information)			(Dollars in thousands, except prices and per Mcfe information)		
Revenues:						
Oil and gas revenues	$ 1,985	$ 2,785	-29%	$ 2,711	$ 1,599	70%
Marketing and other, net	(395)	50	-890%		(71)	n/a
Total revenues	1,590	2,835	-44%	2,711	1,528	77%
Daily sales volumes:						
Natural gas (MMcf)	7.9	9.9	-20%	8.3	4.9	69%
Oil and liquids (Bbl)	227	192	18%	224	195	15%
Equivalents production (MMcfe 6:1)	9.2	11.1	-17%	9.6	6.1	57%
Average price realized:						
Natural gas (Mcf)	$ 2.01	$ 2.59	-22%	$ 3.03	$ 2.89	5%
Oil and liquids (Bbl)	25.62	23.83	8%	19.37	16.25	19%
Direct lifting costs	$ 476	$ 434	10%	$ 371	$ 217	71%
Average direct lifting costs/Mcfe	0.56	0.43	30%	0.42	0.39	8%
Other production costs	419	590	-29%	593	337	76%
General and administrative, net	646	452	43%	405	296	37%
Depreciation, depletion and amortization	901	1,079	-16%	663	438	51%
Interest expense, net	164	270	-39%	31	53	-42%
Income tax provision (benefit)	(382)		n/a	317	21	1410%

(1) Volumetric sales figures for Canadian activities are presented net before royalty interests.

Revenues from oil and gas sales of BFC for the third quarter of 2001 were $2.0 million, a 29% decrease from 2000. The decrease was due primarily to decreased gas prices and natural production declines in all operating areas and the divestiture in January 2001 of the Company's entire working interests and related leasehold rights in the San Juan Basin, partially offset by production increases in the Piceance and Permian Basins.

Revenues from oil, liquids and gas sales of CEC for the third quarter of 2001 were $2.7 million, a 70% increase from the prior year period. The increase was due primarily to increased oil, liquids, and gas production and higher oil, liquids and gas prices.

BFC's average production for the third quarter of 2001 was 227 barrels of oil per day and 7.9 million cubic feet (MMcf) of gas per day, a decrease of 17% from the same period in 2000 on a Mcf equivalent (Mcfe) basis where one barrel of oil is equal to six Mcf of gas. In January 2001, the Company divested its entire working interests and related leasehold rights in the San Juan Basin. This accounted for substantially all of the decrease in U.S. natural gas production compared to the third quarter of 2000 as production increases in the Piceance and Permian Basins offset natural production declines in all operating areas. The increase in oil production was due to successful drilling activities conducted during 2001 in the Permian Basin, partially offset by natural production declines. During the third quarter of 2001, BFC participated in the drilling of 9 gross (6.9 net) wells compared to 6 gross (1.1 net) wells in 2000.

CEC's average production for the third quarter of 2001 was 224 barrels of oil and liquids per day and 8.3 MMcf of gas per day, an increase of 57% on a Mcfe basis from the same period in 2000. The increase was due primarily to successful drilling and recompletion activities in the Carbon and Rowley areas of Central Alberta. During the third quarter of 2001, CEC participated in the drilling of 2 gross (2 net) wells. CEC did not have any drilling activity during the comparable period in 2000.

Average oil prices realized by BFC increased 8% from $23.83 per barrel for the third quarter of 2000 to $25.62 for 2001. The average oil price includes hedge losses of $126,000 for the third quarter of 2000. There was no oil hedge activity for the third quarter of 2001. Average natural gas prices realized by BFC decreased 22% from $2.59 per Mcf for the third quarter of 2000 to $2.01 for 2001. The average natural gas price includes hedge losses of $903,000 and $280,000 for the third quarter of 2000 and 2001, respectively.

Average oil and liquids prices realized by CEC increased 19% from $16.25 per barrel for the third quarter of 2000 to $19.37 for 2001. The average oil price includes hedge losses of $58,000 for the third quarter of 2000. There was no oil hedge activity for the third quarter of 2001. Average natural gas prices realized by CEC increased 5% from $2.89 per Mcf for the third quarter of 2000 to $3.03 for 2001. The average natural gas price includes hedge losses of $384,000 for the third quarter of 2000 compared to hedge gains of $191,000 for 2001.

For the third quarter of 2001, BFC recorded a $625,000 impairment for an outstanding account receivable from a purchaser of the Company's gas production. The Company is currently pursuing its available options regarding the collection of this account. This impairment was partially offset by mark-to-market gains of $158,000 on a derivative contract that does not qualify for hedge accounting treatment under provision of SFAS No. 133. In conjunction with the adoption of SFAS No. 133 on January 1, 2001, 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 this derivative contract.

Direct lifting costs incurred by BFC were $476,000 or $.56 per Mcfe for the third quarter of 2001 compared to $434,000 or $.43 per Mcfe for 2000. The increase was primarily due to well workovers and equipment repairs in the Permian and Piceance Basins performed in the third quarter of 2001.

Other production costs incurred by BFC consisting of severance taxes and production overhead, were $419,000 for the third quarter of 2001 compared to $590,000 for 2000. The decrease was primarily due to lower severance taxes due to lower gas prices and declines in gas production.

Direct lifting costs incurred by CEC were $371,000 or $.42 per Mcfe for the third quarter of 2001 compared to $217,000 or $.39 per Mcfe for 2000.

Other production costs incurred by CEC consisting of net Crown and other royalty expense were $593,000 for the third quarter of 2001 compared to $337,000 for 2000. The increase was due to a rise in net Crown royalties due to higher oil and gas prices and increased production.

General and administrative expenses net of overhead reimbursements incurred by BFC increased 43% from $452,000 for the third quarter of 2000 to $646,000 for 2001. The increase was primarily due to a reduction in overhead reimbursements as a result of the sale of the Company's San Juan Basin properties, salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures.

General and administrative expenses net of overhead reimbursements incurred by CEC increased 37% from $296,000 for the third quarter of 2000 to $405,000 for 2001. The increase was primarily due to salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures.

Interest expense incurred by BFC decreased 39% from $270,000 for the third quarter of 2000 to $164,000 for 2001. The decrease was due primarily to a reduction in debt as a result of proceeds received from the divestiture of the Company's San Juan Basin properties, decreased margin deposits related to the Company's derivative positions, and a decline in interest rates, partially offset by increased funding requirements for capital expenditures.

Interest expense incurred by CEC decreased 42% from $53,000 for the third quarter of 2000 to $31,000 for 2001. The decrease was due primarily to a reduction in debt as a result of increased cashflow from operating activities and a decline in interest rates, partially offset by increased funding requirements for capital expenditures.

Depreciation, depletion and amortization (DD&A) of the Company's oil and gas assets is determined based upon the units of production method. This expense is typically based on the historical capitalized costs incurred to find, develop and recover oil and gas reserves. However, the Company's current DD&A rate is determined primarily by the purchase price the Company allocated to oil and gas properties in its acquisitions of BFC and CEC and the proved reserves which the Company acquired in the acquisitions.

DD&A expense incurred by BFC decreased 16% from $1.1 million for the third quarter of 2000 to $901,000 for 2001. The decrease was due primarily to decreased production. DD&A expense was $1.06 per Mcfe for the third quarter of 2001 and 2000.

DD&A expense incurred by CEC increased 51% from $438,000 for the third quarter of 2000 to $663,000 for 2001. The increase was due primarily to increased production. DD&A expense was $.75 per Mcfe for the third quarter of 2001 compared to $.78 per Mcfe for 2000.

Income tax benefit recorded by BFC was $382,000 for the third quarter of 2001, an effective tax rate of 38%. BFC did not record a provision for income taxes for the third quarter of 2000.

Income tax expense incurred by CEC was $317,000 for the third quarter of 2001, an effective tax rate of 49% compared to $21,000 and an effective tax rate of 11% for 2000.

The following table and the discussion that follows present comparative revenue, sales, volumes, average sales prices, expenses and the percentage change between periods for the nine months ended September 30, 2001 and 2000. The Company's Canadian operations were established in February 2000 through an exchange offer of Carbon shares for shares of CEC. The following table is a pro forma presentation, as if the acquisition of CEC occurred on January 1, 2000.

	United States Nine Months Ended September 30,			Canada (1) Nine Months Ended September 30,		
	2001	2000	Change	2001	2000	Change
	(Dollars in thousands, except prices and per Mcfe information)			(Dollars in thousands, except prices and per Mcfe information)		
Revenues:						
Oil and gas revenues	$ 8,255	$ 7,464	11%	$ 11,560	$ 4,599	151%
Marketing and other, net	857	157	446%		(71)	n/a
Total revenues	9,112	7,621	20%	11,560	4,528	155%
Daily sales volumes:						
Natural gas (MMcf)	7.3	9.2	-21%	8.6	5.0	72%
Oil and liquids (Bbl)	227	187	21%	231	180	28%
Equivalent production (MMcfe 6:1)	8.7	10.3	-16%	10.0	6.1	64%
Average price realized:						
Natural gas (Mcf)	$ 3.30	$ 2.47	34%	$ 4.28	$ 2.61	64%
Oil and liquids (Bbl)	27.10	24.06	13%	23.33	20.44	14%
Direct lifting costs	$ 1,256	$ 1,176	7%	$ 1,168	$ 614	90%
Average direct lifting costs/Mcfe	0.53	0.41	29%	0.43	0.37	16%
Other production costs	1,458	1,464	0%	2,358	732	222%
General and administrative, net	2,033	1,323	54%	1,332	845	58%
Depreciation, depletion and amortization	2,442	2,929	-17%	1,958	1,309	50%
Interest expense, net	481	652	-26%	124	152	-18%
Income tax provision	540		n/a	1,970	329	499%

(1) Volumetric sales figures for Canadian activities are presented net before royalty interests.

Revenues from oil and gas sales of BFC for the first nine months of 2001 were $8.3 million, an increase of 11% from 2000. The increase was due primarily to increased oil and gas prices and production increases in the Piceance and Permian Basins partially offset by natural production declines in all operating areas and the divestiture in January 2001 of the Company's entire working interests and related leasehold rights in the San Juan Basin.

Revenues from oil, liquids and gas sales of CEC for the first nine months of 2001 were $11.6 million, an increase of 151% from the prior year period. The increase was due primarily to increased oil, liquid and gas production and higher oil, liquids and gas prices.

BFC's average production for the first nine months of 2001 was 227 barrels of oil per day and 7.3 million cubic feet (MMcf) of gas per day, a decrease of 16% from the same period in 2000 on a Mcf equivalent (Mcfe) basis where one barrel of oil is equal to six Mcf of gas. In January 2001, the Company divested its entire working interests and related leasehold rights in the San Juan Basin. This accounted for substantially all of the decrease in U.S. natural gas production compared to the first nine months of 2000 as production increases in the Piceance and Permian Basins offset natural production declines in all operating areas. The increase in oil production was due to successful drilling activities conducted during 2001 in the Permian Basin, partially offset by natural production declines. During the first nine months of 2001, BFC participated in the drilling of 24 gross (14.8 net) wells compared to 14 gross (6.8 net) wells in 2000.

CEC's average production for the first nine months of 2001 was 231 barrels of oil and liquids per day and 8.6 MMcf of gas per day, an increase of 64% on a Mcfe basis from the same period in 2000. The increase was due primarily to successful drilling and recompletion activities in the Carbon and Rowley areas of Central Alberta. During the first nine months of 2001, CEC participated in the drilling of 7 gross (7 net) wells. CEC did not have any drilling activity during the comparable period in 2000.

Average oil prices realized by BFC increased 13% from $24.06 per barrel for first nine months of 2000 to $27.10 for 2001. The average oil price includes hedge losses of $228,000 for the first nine months of 2000. There was no oil hedge activity for the first nine months of 2001. Average natural gas prices realized by BFC increased 34% from $2.47 per Mcf for the first nine months of 2000 to $3.30 for 2001. The average natural gas price includes hedge losses of $1.3 million and $1.6 million for the first nine months of 2000 and 2001, respectively.

Average oil and liquids prices realized by CEC increased 14% from $20.44 per barrel for the first nine months of 2000 to $23.33 for 2001. The average oil price includes hedge losses of $93,000 for the first nine months of 2000. There was no oil hedge activity for the first nine months of 2001. Average natural gas prices realized by CEC increased 64% from $2.61 per Mcf for the first nine months of 2000 to $4.28 for 2001. The average natural gas price includes hedge losses of $532,000 and $730,000 for the first nine months of 2000 and 2001, respectively.

Marketing and other revenue realized by BFC was $857,000 for the first nine months of 2001, compared to $157,000 for 2000. This increase was primarily due to mark-to-market gains of $1.2 million on a derivative contract that does not qualify for hedge accounting treatment under provisions of SFAS No. 133. In conjunction with the adoption of SFAS No. 133, on January 1, 2001, 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 this derivative contract. This increase was partially offset by a $625,000 impairment related to an outstanding account receivable from a purchaser of the Company's gas production. The Company is currently pursuing its available options regarding collection of this account.

Direct lifting costs incurred by BFC were $1.3 million or $.53 per Mcfe for the first nine months of 2001 compared to $1.2 million or $.41 per Mcfe for 2000. The per Mcfe increase was primarily due to well workovers and equipment repairs in the Permian and Piceance Basins performed in 2001.

Other production costs incurred by BFC consisting of severance taxes and production overhead, were $1.5 million for the first nine months of 2001 and 2000. Higher severance taxes due to higher prices were offset by declines in gas production.

Direct lifting costs incurred by CEC were $1.2 million or $.43 per Mcfe for the first nine months of 2001 compared to $614,000 or $.37 per Mcfe for 2000.

Other production costs incurred by CEC consisting of net Crown and other royalty expense were $2.4 million for the first nine months of 2001 compared to $732,000 for 2000. The increase was due to a rise in net Crown royalties due to higher oil and gas prices and increased production.

General and administrative expenses net of overhead reimbursements incurred by BFC increased 54% from $1.3 million for the first nine months of 2000 to $2.0 million for 2001. The increase was primarily due to a reduction in overhead reimbursements as a result of the sale of the Company's San Juan Basin properties, salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures.

General and administrative expenses net of overhead reimbursements incurred by CEC increased 58% from $845,000 for the first nine months of 2000 to $1.3 million for 2001. The increase was primarily due to salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures.

Interest expense incurred by BFC decreased 26% from $652,000 for the first nine months of 2000 to $481,000 for 2001. The decrease was due primarily to a reduction in debt as a result of proceeds received from the divestiture of the Company's San Juan Basin properties, decreased margin deposits related to the Company's derivative position and a decrease in interest rates, partially offset by increased funding requirements for capital expenditures.

Interest expense incurred by CEC decreased 18% from $152,000 for the first nine months of 2000 to $124,000 for 2001. The decrease was due primarily to a reduction in debt as a result of increased cash flow from operating activities and a decline in interest rates, partially offset by increased funding requirements for capital expenditures.

Depreciation, depletion and amortization (DD&A) of the Company's oil and gas assets is determined based upon the units of production method. This expense is typically based on the historical capitalized costs incurred to find, develop and recover oil and gas reserves. However, the Company's current DD&A rate is determined primarily by the purchase price the Company allocated to oil and gas properties in its acquisitions of BFC and CEC and the proved reserves which the Company acquired in the acquisitions.

DD&A expense incurred by BFC decreased 17% from $2.9 million for the first nine months of 2000 to $2.4 million for 2001. The decrease was due primarily to decreased production. DD&A expense was $1.03 per Mcfe for the first nine months of 2001 and 2000.

DD&A expense incurred by CEC increased 50% from $1.3 million for the first nine months of 2000 to $2.0 million for 2001. The increase was due primarily to increased production. DD&A expense was $.72 per Mcfe for the first nine months of 2001 compared to $.78 per Mcfe for 2000.

Income tax expense incurred by BFC was $540,000 for the first nine months of 2001, an effective tax rate of 37%. BFC did not record a provision for income taxes for the first nine months of 2000.

Income tax expense incurred by CEC was $2.0 million for the first nine months of 2001, an effective tax rate of 43% compared to $329,000 and an effective tax rate of 38% for 2000.

Capital Resources and Liquidity

At September 30, 2001, Carbon had $63.7 million of assets on its balance sheet. Total capitalization was $49.7 million, consisting of 69% of stockholders' equity and 31% of debt.

United States Facility The Company moved its credit facility from U.S. Bank National Association to Wells Fargo Bank West, National Association in the third quarter of 2000.

The facility is an oil and gas reserve based line-of-credit and had a borrowing base of $16.3 million with outstanding borrowings of $13.5 million at September 30, 2001. The borrowing base is subject to a $500,000 per month reduction schedule through November 1, 2001, at which time the borrowing base will be $15.3 million. The facility is secured by certain U.S. oil and gas properties of the Company and is scheduled to convert to a term note on October 1, 2002. This facility is scheduled to have a maturity date of either the economic half life of the Company's remaining U.S. reserves on the last day of the revolving period, or October 1, 2006, whichever is earlier. The facility bears interest at a rate equal to LIBOR plus 1.75% or Wells Fargo Bank West Prime, at the option of the Company. The Company's average borrowing rate was approximately 5.4% at September 30, 2001. The borrowing base is based upon the lender's semi-annual evaluation of the Company's proved oil and gas reserves.

The credit agreement contains 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 is also required to maintain certain financial ratios.

Canadian Facility In June 2001, the Company secured an increase to approximately $9.2 million from approximately $4.3 million in the borrowing base of its facility with the Canadian Imperial Bank of Commerce (CIBC). Outstanding borrowings against the facility were $1.7 million at September 30, 2001. 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, 2002. 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 any principal payments under the term loan section of the facility until October 2002 at the earliest. As such, no amounts under the Canadian facility have been classified as current on the September 30, 2001 balance sheet. The Canadian facility bears interest at the CIBC Prime rate plus 0.5%. The rate was approximately 5.75% at September 30, 2001.

The Canadian facility contains various covenants which limit the Company's ability to pay dividends, purchase treasury shares, incur indebtedness, sell properties, or merge with another entity.

The agreement with CIBC also provides for $3.5 million of credit which can be utilized for commodity swaps covering a portion of the Company's oil and gas production, forward exchange contracts and gas purchase and sales transactions. The Company currently utilizes the swap facility to hedge a portion of its Canadian production.

For the nine months ended September 30, 2001, net cash provided by operating activities was $10.7 million compared to $1.1 million in 2000. The increase is due primarily to increases in net income and non-cash charges to net income and a decline in margin deposit requirements for the Company's derivative accounts in 2001 compared to 2000. Net cash used in investing activities was $10.9 million for the nine months ended September 30, 2001 compared to $6.7 million for 2000. Included in the cash used in investing activities for the nine months ended September 30, 2001, was $6.8 million in proceeds related to the disposition of the Company's entire working interests and related leasehold rights in the San Juan Basin.

Carbon's primary cash requirements will be to finance development and exploration expenditures, finance acquisitions, repay debt, and for general working capital needs. Future cash flow is subject to a number of variables including the level of production and oil and natural gas prices and there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures or that increased capital expenditures will not be undertaken. In January 2001, Carbon closed the sale of its entire working interests and related leasehold rights in the San Juan Basin. The proceeds from the sale after adjustments were $6.8 million. The Company anticipates that capital expenditures, exclusive of acquisitions (if any) or divestitures will approximate $22.1 million in 2001. Carbon believes that available borrowings under its credit agreements, the proceeds from the sale of San Juan properties, projected operating cash flows and cash on hand will be sufficient to cover its working capital, capital expenditures, planned development activities and debt service requirements for the next 12 months. If necessary, Carbon will explore outside funding opportunities including equity or additional debt financings for use in expanding Carbon's operations or in consummating any significant acquisition. Carbon does not know however, whether any financing can be accomplished on terms that are acceptable to the Company.

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 and for all business combinations accounted for under the pooling method initiated before but completed after June 30, 2001. The adoption of SFAS No. 141 is not expected to 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 financial accounting and reporting for goodwill and other intangible assets. SFAS No. 142 is effective for fiscal years beginning after December 15, 2001, and applies to all goodwill and other intangibles recognized in the financial statements at that date. The adoption of SFAS No. 142 is not expected to have a material impact on the Company's financial position or results of operations.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143 requires entities to record the fair value of liabilities for retirement obligations of acquired assets. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. The Company will adopt SFAS No. 143 on January 1, 2003, but has not yet quantified the effects of adopting SFAS No. 143 on its financial position or results of operations.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment of Disposal of Long-Lived Assets". SFAS No. 144 supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." SFAS No. 144 establishes a single accounting model for long-lived assets to be disposed of by sale and requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001. The Company will adopt SFAS No. 144 on January 1, 2002, and does not believe adoption of SFAS No. 144 will have a material effect on its financial position or results of operations.

Certain Factors That May Affect Future Results

Statements that are not historical facts contained in this report are forward-looking statements that involve risks and uncertainties that could cause actual results to differ from projected results. 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, drilling of wells, 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 expectation 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 expectation and assumptions will prove to be correct. Factors that could cause actual results to differ materially (Cautionary Disclosures) are described, among other places, in the Marketing, Competition, Government Regulation, Environmental Regulation and Operating Hazards sections of the Company's 2000 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 Disclosures.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

The Company has risk exposure to interest rate volatility in its outstanding debt. The sensitivity analysis that follows presents the change in the 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. As the Company presently has only floating rate debt, interest rate changes would not affect the fair value of these floating rate instruments but would impact future earnings and cash flows, assuming all other factors are held constant. The carrying amount of the Company's floating rate debt approximates its fair value. At September 30, 2001, the Company had $13.5 million of floating rate debt through its facility with Wells Fargo Bank West and $1.7 million through its facility with CIBC. Assuming constant debt levels, earnings and cash flow impacts for the next twelve month period from September 30, 2001 due to a one percent change in interest rates would be approximately $135,000 before taxes for the facility with Wells Fargo Bank West and $17,000 before taxes for the facility with CIBC.

Foreign Currency Risk

The Canadian dollar is the functional currency of CEC and is subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. The Company has not entered into any 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 as well as regional supply and demand. Worldwide political events can also impact commodity prices. The Company from time to time may use certain financial instruments in an attempt to reduce exposure to market fluctuations in the price of oil and natural gas. The Company may hedge price risk of a portion of the Company's production with swap, collar, futures, and floor and ceiling arrangements as described in Note 2 to the financial statements. Pursuant to Company guidelines, the Company is to engage in these activities only as a hedging mechanism. The Company has a Risk Management Committee to administer its production hedging program 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 when the transactions being hedged are finalized. 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 table below sets forth BFC's and CEC's derivative financial instrument positions that qualify for hedge accounting treatment on its oil and natural gas production as of September 30, 2001.

Futures and swaps:

BFC Contracts				CEC Contracts			
Year	**Bbl/ MMBtu**	**Weighted Average Fixed Price Bbl/ MMBtu**	**Derivative Asset/ (Liability) (thousands)**	**Year**	**Bbl/ MMBtu**	**Weighted Average Fixed Price Bbl/ MMBtu**	**Derivative Asset/ (Liability) (thousands)**
Gas				**Gas**			
2001	80,000	$ 2.28	$ 10	2001	40,000	$ 2.21	$ 22

Collars:

BFC Contracts					CEC Contracts				
Year	**Bbl/ MMBtu**	**Average Floor**	**Average Ceiling**	**Derivative Asset/**	**Year**	**Bbl/ MMBtu**	**Average Floor**	**Average Ceiling**	**Derivative Asset/**

	BFC Contracts					CEC Contracts			
		Bbl/ MMBtu	Bbl/ MMBtu	(Liability) (thousands)			Bbl/ MMBtu	Bbl/ MMBtu	(Liability) (thousands)
Oil					**Oil**				
2001	18,400	$ 24.00	$ 29.10	$ 27	2001	9,200	$ 24.00	$ 29.05	$ 13
2002	73,000	$ 22.00	$ 27.50	$ 46	2002	36,500	$ 22.00	$ 27.50	$ 25
Gas					**Gas**				
2001	123,000	$ 2.62	$ 3.37	$ 92	2001	117,000	$ 2.84	$ 3.84	$ 202
2002	304,000	$ 2.50	$ 3.50	$ 37	2002	288,000	$ 2.42	$ 3.42	$ 83

With the adoption of SFAS No. 133 on January 1, 2001, the Company has a derivative contract that no longer qualifies for hedge accounting treatment. The table below sets forth the position of this contract as of September 30, 2001.

Swaps:

BFC Contracts			
Year	Bbl/ MMBtu	Weighted Average Fixed Price Bbl/ MMBtu	Derivative Asset/ (Liability) (thousands)
Gas			
2001	62,000	$ 2.04	$ 43

During the first nine months of 2001, the Company entered into Permian Basin basis swap contracts that do not qualify for hedge accounting treatment. The value of these contracts were $8,000 as of September 30, 2001. At September 30, 2001, basis swaps covering 40,000 MMBtu were outstanding and expire on or before October 31, 2001.

Inflation and Changes in Prices

While certain of its costs are affected by the general level of inflation, factors unique to the oil and natural gas industry result in independent price fluctuations. Over the past five years, significant fluctuations have occurred in oil and natural gas prices. Although it is particularly difficult to estimate future prices of oil and natural gas, price fluctuations have had, and will continue to have, a material effect on the Company.

PART II OTHER INFORMATION

Item 1-5 Not applicable

Item 6. (a) Exhibits

10.1 Credit agreement dated as of September 14, 2001 between CEC Resources Ltd. and Canadian Imperial Bank of Commerce *

(b) No reports on Form 8-K were filed by the registrant during the quarter ended September 30, 2001.

*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, 2001	By:	/s/ PATRICK R. MCDONALD
		President and Chief Executive Officer
Date: November 14, 2001	By:	/s/ KEVIN D. STRUZESKI
		Treasurer and Chief Financial Officer

Exhibit Number	Exhibit
10.1	Credit Agreement dated as of September 14, 2001 between CEC Resources Ltd. and Canadian Imperial Bank of Commerce.