CARBON ENERGY CORP
Form 10-Q
August 19, 2002

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 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	**84-1515097**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1700 Broadway, Suite 1150, Denver, CO	**80290**
(Address of principal executive offices)	(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 August 12, 2002
Common stock, no par value	6,141,090 shares

CARBON ENERGY CORPORATION
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PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

CARBON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands)

(unaudited)

	June 30, 2002	December 31, 2001
ASSETS		
Current assets:		
Cash	$	$
Accounts receivable, trade	2,417	2,258
Accounts receivable, other	55	53
Prepaid expenses and other	445	317
Current derivative asset	77	341
Total current assets	2,994	2,969

	June 30, 2002		December 31, 2001
Property and equipment, at cost:			
Oil and gas properties, using the full cost method of accounting:			
Unproved properties		8,286	7,500
Proved properties		67,800	62,750
Furniture and equipment		935	927
		77,021	71,177
Less accumulated depreciation, depletion and amortization		(29,124)	(12,226)
Property and equipment, net		47,897	58,951
Deposits and other long-term assets		538	448
Total assets	$	51,429	$ 62,368

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

CARBON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands)

(unaudited)

	June 30, 2002	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 3,763	$ 5,113
Accrued production taxes payable	480	527
Income taxes payable		1,168
Undistributed revenue and other	1,136	1,062
Current derivative liability	252	76
Deferred income taxes		74
Total current liabilities	5,631	8,020
Long-term debt	23,296	17,870
Other long-term liabilities	113	18
Deferred income taxes	2,904	2,577
Minority interest	28	29

	June 30, 2002	December 31, 2001
Stockholders' equity:		
Preferred stock, no par value:		
10,000,000 shares authorized, none outstanding		
Common stock, no par value:		
20,000,000 shares authorized, issued, and 6,104,092 shares and 6,079,225 shares outstanding at June 30, 2002 and December 31, 2001, respectively	31,933	31,799
Retained earnings (accumulated deficit)	(12,083)	2,538
Accumulated other comprehensive loss	(393)	(483)
Total stockholders' equity	19,457	33,854
Total liabilities and stockholders' equity	$ 51,429	$ 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 June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Revenues:				
Oil and gas sales	$ 4,036	$ 5,751	$ 7,584	$ 13,367
Marketing and other, net	101	565	179	1,252
	4,137	6,316	7,763	14,619
Expenses:				
Oil and gas production costs	1,226	1,261	2,411	2,629
Depreciation, depletion and amortization	1,697	1,448	3,437	2,836
Full cost ceiling impairment	13,218		13,218	
General and administrative, net	1,161	1,218	2,490	2,314
Interest and other, net	260	224	453	410
Total operating expenses	17,562	4,151	22,009	8,189
Minority interest	1	(3)	1	(25)
Income (loss) before income taxes	(13,424)	2,162	(14,245)	6,405
Income tax provision:				
Current	33	769	60	1,488
Deferred	632	89	316	1,087

	Three Months Ended June 30,		Six Months Ended June 30,	
Total taxes	665	858	376	2,575
Net income (loss) before cumulative effect of change in accounting principle	(14,089)	1,304	(14,621)	3,830
Cumulative effect of change in accounting principle, net of tax				(1,510)
Net income (loss)	$ (14,089)	$ 1,304	$ (14,621)	$ 2,320
Average number of common shares outstanding:				
Basic	6,097	6,048	6,091	6,037
Diluted	6,097	6,336	6,091	6,291
Earnings (loss) per share basic:				
Net income (loss) before cumulative effect of change in accounting principle	$ (2.31)	$ 0.22	$ (2.40)	$ 0.63
Cumulative effect of change in accounting principle, net of tax				(0.25)
	$ (2.31)	$ 0.22	$ (2.40)	$ 0.38
Earnings (loss) per share diluted:				
Net income (loss) before cumulative effect of change in accounting principle	$ (2.31)	$ 0.21	$ (2.40)	$ 0.61
Cumulative effect of change in accounting principle, net of tax				(0.24)
	$ (2.31)	$ 0.21	$ (2.40)	$ 0.37

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

CARBON ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(unaudited)

	For the Six Months Ended June 30, 2002	2001
Cash flows from operating activities:		
Net income (loss)	$ (14,621)	$ 2,320
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization expense	3,437	2,836
Full cost ceiling impairment	13,218	

	For the Six Months Ended June 30,	
Amortization of deferred hedging gains	(122)	
Unrealized derivative gains		(1,116)
Deferred income tax	316	1,087
Cumulative effect of change in accounting principle		1,510
Minority interest	(1)	25
Vesting of restricted stock grants	77	63
Changes in operating assets and liabilities:		
Decrease (increase) in:		
Accounts receivable	78	1,135
Amounts due from broker		3,164
Prepaid expenses and other assets	(77)	49
Increase (decrease) in:		
Accounts payable and accrued expenses	(2,871)	(3,620)
Undistributed revenue	55	32
Net cash provided by (used in) operating activities	(511)	7,485
Cash flows from investing activities:		
Capital expenditures for oil and gas properties	(4,747)	(11,256)
Proceeds from property sales	2	6,758
Acquisition of CEC Resources	(6)	(203)
Capital expenditures for support equipment		(464)
Net cash used in investing activities	(4,751)	(5,165)
Cash flows from financing activities:		
Proceeds from notes payable	14,495	30,796
Principal payments on notes payable	(9,300)	(33,227)
Proceeds from issuance of common stock	57	157
Net cash provided by (used in) financing activities	5,252	(2,274)
Effect of exchange rate changes on cash	10	(67)
Net increase (decrease) in cash		(21)
Cash, beginning of period		21
Cash, end of period	$	$
Supplemental cash flow information:		
Cash paid for interest	$ 444	$ 538
Cash paid for taxes	1,308	384

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) 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 Unites States include the Piceance Basin in Colorado, the Uintah Basin in Utah, the Permian Basin in New Mexico, Kansas 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). 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 June 30, 2002 and the results of operations and 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.

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

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 is 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. Accordingly, 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 are included as additional accumulated DD&A in the accompanying balance sheet. 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.

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 other 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.

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 months and six months ended June 30, 2002 and 2001 (in thousands):

	United States Three Months Ended June 30,		**Canada Three Months Ended June 30,**		**United States Six Months Ended June 30,**		**Canada Six Months Ended June 30,**	
	2002	**2001**	**2002**	**2001**	**2002**	**2001**	**2002**	**2001**
Oil	$ (16)	$	$	$	$ (16)	$	$ 11	$
Natural gas	13	(757)	(79)	(202)	64	(1,287)	16	(921)

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 June 30, 2002:

Swaps:

Carbon USA Contracts	**CEC Contracts**

Carbon USA Contracts				CEC Contracts			
Time Period	Bbl/ MMBtu	Weighted Average Fixed Price Bbl/ MMBtu	Derivative Asset/ (Liability)	Time Period	MMBtu	Weighted Average Fixed Price MMBtu	Derivative Asset/ (Liability)
			(in thousands)				(in thousands)
Gas				**Gas**			
07/01/02 - 12/31/02	460,000	$ 2.46	$ 121	07/01/02 - 12/31/02	378,000	$ 2.52	$ (46)
01/01/03 - 06/30/03	455,500	3.08	(102)	01/01/03 - 12/31/03	216,000	2.92	(95)
Oil							
07/01/02 - 12/31/02	18,400	$ 24.55	$ (24)				
01/01/03 - 03/31/03	9,000	24.55	(4)				

Collars:

CEC Contracts				
Time Period	Bbl/ MMBtu	Average floor Bbl/ MMBtu	Average Ceiling Bbl/ MMBtu	Derivative Asset/ (Liability)
				(in thousands)
Gas				
07/01/02 - 10/31/02	117,000	$ 2.50	$ 3.52	$ 39
Oil				
07/01/02 - 12/31/02	18,400	$ 22.00	$ 27.50	$ (13)

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In addition to the derivative contracts discussed above, the Company may enter into long-term sales contracts for a portion of its natural gas and oil production. The table below sets forth fixed price sales contracts at June 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**		
07/01/02 - 12/31/02	184,000	$ 2.60	01/01/03 - 12/31/03	365,000	$ 3.38
01/01/03 - 03/31/03	90,000	2.60			

During the first six months of 2002, net hedging gains of $91,000 ($55,000 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 $659,000 ($389,000 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 six months of 2002. As of June 30, 2002, the Company had net unrealized derivative losses of $322,000 ($194,000 after tax). Based on future indices for oil, natural gas and interest rates in effect on June 30, 2002, the Company expects to reclassify $209,000 of these net unrealized losses to earnings during the next twelve month period.

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 on future income. Gains or losses from financial instruments 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 June 30, 2002:

Notional Amount	Contract Expiration Date	LIBOR Fixed Rate	All-In LIBOR Fixed Rate	Derivative Asset/ (Liability)
(in thousands)				
$ 3,700	May 2003	3.46%	5.21%	$ (50)
2,000	October 2003	3.77%	5.52%	(40)
800	October 2003	3.82%	5.57%	(17)
1,000	March 2004	4.15%	5.90%	(22)
2,500	April 2004	4.24%	5.99%	(68)

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 $499,000 and ($43,000) for the six months ended June 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 six months ended June 30, 2002 and 2001:

	Six Months Ended June 30,	
	2002	2001
	(in thousands)	
Net income (loss)	$ (14,621)	$ 2,320
Other comprehensive income (loss), net of tax:		
Currency translation adjustment	499	(43)
Cumulative effect of change in accounting principle January 1, 2001		(2,768)
Reclassification adjustment for settled hedging contracts	(130)	1,093
Changes in fair value of outstanding hedge positions	(279)	1,360
Other comprehensive income (loss)	90	(358)
Comprehensive income (loss)	$ (14,531)	$ 1,962

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 based on future commodity prices and deferred a corresponding amount in accumulated other comprehensive income.

The amount deferred in accumulated other comprehensive income at June 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 second half of 2002 are $124,000. Marketing and other revenue for the three and six months ended June 30, 2002 include $70,000 and $122,000, respectively, of amounts reclassified out of 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 six months ended June 30, 2002, basic and diluted earnings per share are the same, as all potentially dilutive securities would be anti-dilutive.

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

Recent Accounting Pronouncements In 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 fiscal years beginning after June 15, 2002. 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. 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.

4. Long-term Debt

U.S. 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 June 30, 2002, the borrowing base was $20.0 million with outstanding borrowings of $17.7 million. 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 3.8% at June 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.

In August 2002, the Company and Wells Fargo amended the credit facility to provide for a reduction to the borrowing base of $400,000 per month from September 2002 through January 2003, at which time the borrowing base will be $18.0 million. The amended facility has a maturity date of July 1, 2005 with no principal payments required until that date.

As a result of the full cost ceiling impairment discussed previously, as of June 30, 2002 the Company was not in compliance with the tangible net worth covenant under the credit facility. In conjunction with the amendment discussed above, no default was asserted by Wells Fargo and the covenant was amended to reduce the minimum tangible net worth requirement. As of June 30, 2002, the Company would have had a "cushion" of approximately $900,000 based on the amended tangible net worth requirement. Based on the Company's net income projections, management expects to be in compliance with the revised tangible net worth through at least the next twelve months.

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 June 30, 2002 the borrowing base was $9.2 million with outstanding borrowings of $5.5 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 July 2003 at the earliest. As such, no amounts under the CIBC facility have been classified as current on the June 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 4.75% at June 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 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 six months ended June 30, 2002 and 2001 was prepared on the same basis as Carbon's consolidated financial statements.

	Three Months Ended June 30, 2002			Six Months Ended June 30, 2002		
	United States	Canada	Total	United States	Canada	Total
Revenues:						
Oil and gas sales	$ 2,188	$ 1,848	$ 4,036	$ 4,087	$ 3,497	$ 7,584
Marketing and other, net	101		101	179		179
	2,289	1,848	4,137	4,266	3,497	7,763
Expenses:						

	Three Months Ended June 30, 2002			Six Months Ended June 30, 2002		
Oil and gas production costs	828	398	1,226	1,597	814	2,411
Depreciation, depletion, and amortization	1,034	663	1,697	2,116	1,321	3,437
Full cost ceiling impairment	12,003	1,215	13,218	12,003	1,215	13,218
General and administrative, net	746	415	1,161	1,624	866	2,490
Interest, net	207	53	260	370	83	453
Total operating expenses	14,818	2,744	17,562	17,710	4,299	22,009
Minority interest		1	1		1	1
Loss before income taxes	(12,529)	(895)	(13,424)	(13,444)	(801)	(14,245)
Income tax provision (benefit)	1,089	(424)	665	746	(370)	376
Net loss	$ (13,618)	$ (471)	$ (14,089)	$ (14,190)	$ (431)	$ (14,621)
Total assets	$ 29,722	$ 21,707	$ 51,429	$ 29,722	$ 21,707	$ 51,429
Capital expenditures	$ 522	$ 1,790	$ 2,312	$ 1,289	$ 3,458	$ 4,747

	Three Months Ended June 30, 2001			Six Months Ended June 30, 2001		
	United States	Canada	Total	United States	Canada	Total
Revenues:						
Oil and gas sales	$ 2,469	$ 3,282	$ 5,751	$ 6,270	$ 7,097	$ 13,367
Marketing and other, net	565		565	1,252		1,252
	3,034	3,282	6,316	7,522	7,097	14,619
Expenses:						
Oil and gas production costs	976	285	1,261	1,819	810	2,629
Depreciation, depletion and amortization	804	644	1,448	1,541	1,295	2,836
General and administrative, net	767	451	1,218	1,387	927	2,314
Interest, net	185	39	224	317	93	410
Total operating expenses	2,732	1,419	4,151	5,064	3,125	8,189
Minority interest		(3)	(3)		(25)	(25)
Income before income taxes	302	1,860	2,162	2,458	3,947	6,405
Income tax provision	113	745	858	922	1,653	2,575
Net income before cumulative effect of change in accounting principle	189	1,115	1,304	1,536	2,294	3,830
Cumulative effect of change in accounting principle, net of tax				(1,510)		(1,510)
Net income	$ 189	$ 1,115	$ 1,304	$ 26	$ 2,294	$ 2,320
Total assets	$ 39,938	$ 19,201	$ 59,139	$ 39,938	$ 19,201	$ 59,139
Capital expenditures	$ 3,962	$ 1,399	$ 5,361	$ 7,742	$ 3,978	$ 11,720

6. Subsequent Event

In July 2002, the Company closed the sale of certain overriding royalty interests in the Piceance and Permian Basins, receiving net proceeds of approximately $700,000. The proceeds were used to repay amounts outstanding under the Company's credit facilities.

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

All amounts are presented in U.S. dollars.

	United States Three Months Ended June 30,			Canada Three Months Ended June 30,		
	2002	2001	Change	2002	2001	Change
	(Dollars in thousands, except prices and per Mcfe information			(Dollars in thousands, except prices and per Mcfe information		
Revenues:						
Oil and gas revenues	$ 2,188	$ 2,469	-11%	$ 1,848	$ 3,282	-44%
Marketing and other, net	101	565	-82%			n/a
Total revenues	$ 2,289	$ 3,034	-25%	$ 1,848	$ 3,282	-44%
Daily production volumes:						
Natural gas (MMcf)	8.4	7.3	15%	6.4	6.6	-3%
Oil and liquids (Bbl)	242	215	13%	139	159	-13%
Equivalent production (MMcfe 6:1)	9.9	8.6	15%	7.2	7.6	-5%
Average price realized:						
Natural gas (Mcf)	$ 2.19	$ 2.94	-26%	$ 2.76	$ 4.86	-43%
Oil and liquids (Bbl)	23.17	26.61	-13%	20.04	24.48	-18%
Direct lifting costs	$ 373	$ 489	-24%	$ 382	$ 285	34%
Average direct lifting costs/Mcfe	0.41	0.63	-35%	0.58	0.41	41%
Other production costs	455	487	-7%	16		n/a
General and administrative, net	746	767	-3%	415	451	-8%
Depreciation, depletion and amortization	1,034	804	29%	663	644	3%
Full cost ceiling impairment	12,003		n/a	1,215		n/a
Interest expense, net	207	185	12%	53	39	36%
Income tax provision (benefit)	1,089	113	864%	(424)	745	-157%

Revenues from oil and gas sales of Carbon USA for the second quarter of 2002 were $2.2 million, an 11% 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 second quarter of 2002 were $1.8 million, a 44% 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.

Average production in the United States for the second quarter of 2002 was 242 barrels of oil and liquids per day and 8.4 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. During the second quarter of 2002, Carbon USA participated in the drilling of one gross (.1 net) well which was completed as an oil well. During the second quarter of 2001, Carbon USA participated in the drilling of five gross (2.2 net) wells of which two gross (.3 net) wells were completed as oil wells and three gross (1.9 net) wells were completed as gas wells.

Average production in Canada for the second quarter of 2002 was 139 barrels of oil and liquids per day and 6.4 MMcf of gas per day, a decrease of 5% on a Mcfe basis from the same period in 2001.

The decrease was primarily due to natural production declines in all operating areas, partially offset by successful drilling activities in the Carbon and Rowley areas of Central Alberta. During the second quarter of 2002, CEC participated in the drilling of four gross (2.7 net) wells which were completed as gas wells. During the second quarter of 2001, CEC participated in the drilling of two gross (2.0 net) wells which were completed as gas wells.

Average oil and liquids prices realized by Carbon USA decreased 13% from $26.61 per barrel for the second quarter of 2001 to $23.17 for 2002. Average natural gas prices realized by Carbon USA decreased 26% from $2.94 per Mcf for the second quarter of 2001 to $2.19 for 2002. The average natural gas price includes hedge gains of $13,000 for the second quarter of 2002 compared to hedge losses of $757,000 for 2001.

Average oil and liquids prices realized by CEC decreased 18% from $24.48 per barrel for the second quarter of 2001 to $20.04 for 2002. Average natural gas prices realized by CEC decreased 43% from $4.86 per Mcf for the second quarter of 2001 to $2.76 for 2002. The average natural gas price includes hedge losses of $79,000 for the second quarter of 2002 compared to hedge losses of $202,000 for 2001.

Marketing and other revenues in the United States were $101,000 for the second quarter of 2002 compared to $565,000 for 2001. Marketing revenue for the second quarter of 2001 included mark to market gains of $451,000 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 $373,000 or $.41 per Mcfe for the second quarter of 2002 compared to $489,000 or $.63 per Mcfe for 2001. The decrease in direct lifting costs was primarily due to more efficient field operating practices as well as a decrease in the number of well workovers and equipment repairs compared to the second quarter of 2001.

Other production costs incurred by Carbon USA, consisting primarily of severance taxes and production overhead, were $455,000 for the second quarter of 2002 compared to $487,000 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 $382,000 or $.58 per Mcfe for the second quarter of 2002 compared to $285,000 or $.41 per Mcfe for 2001. The higher per Mcfe expense in the second quarter of 2002 was primarily due to higher compression expenses associated with the production of natural gas in Alberta and a change of estimate of certain operating expenses related to non-operated properties which were recorded in the second quarter of 2002.

Other production costs incurred by CEC, consisting primarily of severance taxes, were $16,000 for the second quarter of 2002. There were no such other production costs incurred during the second quarter of 2001. The increase was primarily due to production during the second quarter of 2002 from wells subject to severance taxes.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by Carbon USA decreased 3% from $767,000 for the second quarter of 2001 to $746,000 for 2002.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by CEC decreased 8% from $451,000 for the second quarter of 2001 to $415,000 for 2002.

Interest expense incurred by Carbon USA increased 12% from $185,000 for the second quarter of 2001 to $207,000 for 2002. The increase was due primarily to increased average debt balances in the second quarter of 2002 relative to 2001, partially offset by a decline in interest rates.

Interest expense incurred by CEC increased 36% from $39,000 for the second quarter of 2001 to $53,000 for 2002. The increase was due primarily to increased average debt balances in the second 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 and the volume of proved reserves the Company acquired in the acquisitions.

DD&A expense incurred by Carbon USA was $1.0 million or $1.15 per Mcfe for the second quarter of 2002 compared to $804,000 or $1.03 per Mcfe for 2001. The increased rate is due to the capitalized cost per Mcfe of reserves added to the Company's proved reserves during 2001 compared to the rate established at the time of the acquisition of Carbon USA.

DD&A expense incurred by CEC was $663,000 or $1.01 per Mcfe compared to $644,000 or $.94 per Mcfe for 2001. The increased rate is due to the capitalized cost per Mcfe of reserves added to the Company's proved reserves during 2001 compared to the rate established at the time of the acquisition of CEC.

For purposes of calculating the ceiling test at June 30, 2002, the Company used mainline prices of $1.10/mmbtu in Colorado and Utah and $1.43/mmbtu in Central Alberta. The negative differential of these prices when compared to a U.S. reference price set at Henry Hub at June 30, 2002, was $2.32/mmbtu for Colorado and Utah and $1.99/mmbtu for Central Alberta. This compares to a 36 month historical negative differential of $.37/mmbtu for Colorado and $.29/mmbtu for Central Alberta. Due to these large pricing differentials when compared to a U.S. reference price set at Henry Hub 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 is 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. Accordingly, the Company recorded a $12.0 million and $1.2 million non-cash charge in the United States and Canada, respectively, to reflect these impairments. See Note 2 to the Consolidated Financial Statements for additional information.

Income tax expense recorded by Carbon USA was $1.1 million for the second quarter of 2002, an effective tax rate of (9%), compared to an expense of $113,000 and an effective tax rate of 37% 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 $5.5 million during the second quarter of 2002.

Income tax benefit incurred by CEC was $424,000 for the second quarter of 2002, an effective tax rate of 47%, compared to an expense of $745,000 and an effective tax rate of 40% for 2001. The increase in the effective tax rate for the second quarter of 2002 was due to an adjustment of deferred taxes related to changes in the statutory tax rates. The income tax benefit related to the above mentioned full cost ceiling impairment was $517,000.

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

All amounts are presented in U.S. dollars.

	United States Six Months Ended June 30,			**Canada Six Months Ended June 30,**		
	2002	**2001**	**Change**	**2002**	**2001**	**Change**

	United States Six Months Ended June 30, (Dollars in thousands, except prices and per Mcfe information			Canada Six Months Ended June 30, (Dollars in thousands, except prices and per Mcfe information		
Revenues:						
Oil and gas revenues	$ 4,087	$ 6,270	-35%	$ 3,497	$ 7,097	-51%
Marketing and other, net	179	1,252	-86%			n/a
Total revenues	4,266	7,522	-43%	3,497	7,097	-51%
Daily sales volumes:						
Natural gas (MMcf)	8.8	7.0	26%	6.3	6.8	-7%
Oil and liquids (Bbl)	244	227	7%	147	165	-11%
Equivalent production (MMcfe 6:1)	10.3	8.4	23%	7.2	7.8	-8%
Average price realized:						
Natural gas (Mcf)	$ 2.01	$ 4.04	-50%	$ 2.66	$ 5.16	-48%
Oil and liquids (Bbl)	20.53	27.86	-26%	17.70	26.37	-33%
Direct lifting costs	$ 761	$ 780	-2%	$ 732	796	-8%
Average direct lifting costs/Mcfe	0.41	0.51	-20%	0.56	0.57	-2%
Other production costs	836	1,039	-20%	82	14	486%
General and administrative, net	1,624	1,387	17%	866	927	-7%
Depreciation, depletion and amortization	2,116	1,541	37%	1,321	1,295	2%
Full cost ceiling impairment	12,003		n/a	1,215		n/a
Interest expense, net	370	317	17%	83	93	-11%
Income tax provision (benefit)	746	922	19%	(370)	1,653	-122%

Revenues from oil and gas sales of Carbon USA for the first six months of 2002 were $4.1 million, a 35% 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 six months of 2002 were $3.5 million, a 51% 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.

Average production in the United States for the first six months of 2002 was 244 barrels of oil and liquids per day and 8.8 million cubic feet (MMcf) of gas per day, an increase of 23% 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. During the first six months of 2002, Carbon USA participated in the drilling of three gross (.2 net) wells which were completed as oil wells. During the first six months of 2001, Carbon USA participated in the drilling of fourteen gross (7.5 net) wells of which four gross (.7 net) wells were completed as oil wells, eight gross (5.3 net) were completed as gas wells and two gross (1.5 net) were abandoned as dry holes.

Average production in Canada for the first six months of 2002 was 147 barrels of oil and liquids per day and 6.3 MMcf of gas per day, a decrease of 8% on a Mcfe basis from the same period in 2001. The decrease was primarily due to comparatively large production volumes for the first six months of 2001 related to the initial production from the Company's fourth quarter 2000 drilling program and natural production declines in all operating areas, partially offset by subsequent successful drilling activities in the Carbon and Rowley areas of Central Alberta. During the first six months of 2002, CEC participated in the drilling of six gross (4.2 net) wells of which five gross (3.7 net) were completed as gas wells and one gross (.5 net) was abandoned as a dry hole. During the first six months of 2001, CEC participated in the drilling of five gross (5.0 net) wells which were completed as gas wells.

Average oil and liquids prices realized by Carbon USA decreased 26% from $27.86 per barrel for the first six months of 2001 to $20.53 for 2002. Average natural gas prices realized by Carbon USA decreased 50% from $4.04 per Mcf for the first six months of 2001 to $2.01 for 2002. The average natural gas price includes hedge gains of $64,000 for the first six months of 2002 compared to hedge losses of $1.3 million for 2001.

Average oil and liquids prices realized by CEC decreased 33% from $26.37 per barrel for the first six months of 2001 to $17.70 for 2002. The average oil price includes hedge gains of $11,000 for the first six months of 2002. There was no oil hedge activity for the first six months of 2001. Average natural gas prices realized by CEC decreased 48% from $5.16 per Mcf for the first six months of 2001 to $2.66 for 2002. The average natural gas price includes hedge gains of $16,000 for the first six months of 2002 compared to hedge losses of $921,000 for 2001.

Marketing and other revenues in the United States were $179,000 for the first six months of 2002 compared to $1.3 million for 2001. Marketing revenue for the first six months of 2002 included mark to market gains of $1.1 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.

Direct lifting costs incurred by Carbon USA were $761,000 or $.41 per Mcfe for the first six months of 2002 compared to $780,000 or $.51 per Mcfe for 2001. The decrease in direct lifting costs was primarily due to more efficient field operating practices as well as a decrease in the number of well workovers and equipment repairs compared to the first six months of 2001.

Other production costs incurred by Carbon USA, consisting primarily of severance taxes and production overhead, were $836,000 for the first six months of 2002 compared to $1.0 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 $732,000 or $.56 per Mcfe for the first six months of 2002 compared to $796,000 or $.57 per Mcfe for 2001. Higher compression expenses associated with the production of natural gas in Alberta during the first six months of 2002 were offset by prior period credits for gas processing received during the first six months of 2001.

Other production costs incurred by CEC, consisting primarily of severance taxes, were $82,000 for the first six months of 2002 compared to $14,000 for 2001. The increase was primarily due to increased production during the first six 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 17% from $1.4 million for the first six months of 2001 to $1.6 million for 2002. The increase was primarily due to legal expenses of $160,000 related to the case of Bonneville Fuels Corporation, as plaintiff, vs. Williams Production RMT Company, which proved unsuccessful. For more information regarding this case, see Part II, Item 1 to the Form 10-Q for the quarter ended March 31, 2002.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by CEC decreased 7% from $927,000 for the first six months of 2001 to $866,000 for 2002.

Interest expense incurred by Carbon USA increased 17% from $317,000 for the first six months of 2001 to $370,000 for 2002. The increase was due primarily to increased average debt balances in the first six months of 2002 relative to 2001, partially offset by a decline in interest rates.

Interest expense incurred by CEC decreased 11% from $93,000 for the first six months of 2001 to $83,000 for 2002. The decrease was due primarily to a decline in interest rates, partially offset by increased average debt balances in the first six months of 2002 relative to 2001.

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 and the volume of proved reserves the Company acquired in the acquisitions.

DD&A expense incurred by Carbon USA was $2.1 million or $1.14 per Mcfe for the first six months of 2002 compared to $1.5 million or $1.02 per Mcfe for 2001. The increased rate is due to the capitalized cost per Mcfe of reserves added to the Company's proved reserves during 2001 compared to the rate established at the time of the acquisition of Carbon USA.

DD&A expense incurred by CEC was $1.3 million or $1.02 per Mcfe compared to $1.3 million or $.92 per Mcfe for 2001. The increased rate is due to the capitalized cost per Mcfe of reserves added to the Company's proved reserves during 2001 compared to the rate established at the time of the acquisition of CEC.

For purposes of calculating the ceiling test at June 30, 2002, the Company used mainline prices of $1.10/mmbtu in Colorado and Utah and $1.43/mmbtu in Central Alberta. The negative differential of these prices when compared to a U.S. reference price set at Henry Hub at June 30, 2002, was $2.32/mmbtu for Colorado and Utah and $1.99/mmbtu for Central Alberta. This compares to a 36 month historical negative differential of $.37/mmbtu for Colorado and $.29/mmbtu for Central Alberta. Due to these large pricing differentials when compared to a U.S. reference price set at Henry Hub 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 is 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. Accordingly, the Company recorded a $12.0 million and $1.2 million non-cash charge in the United States and Canada, respectively, to reflect these impairments. See Note 2 to the Consolidated Financial Statements for additional information.

Income tax expense recorded by Carbon USA was $746,000 for the first six months of 2002, an effective tax rate of (6%), compared to an expense of $922,000 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 $5.5 million during the second quarter of 2002.

Income tax benefit incurred by CEC was $370,000 for the first six months of 2002, an effective tax rate of 46%, compared to an expense of $1.7 million and an effective tax rate of 42% for 2001. The increase 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 June 30, 2002, the Company had $51.4 million of assets. Total capitalization was $42.8 million, consisting of 46% of stockholders' equity and 54% of debt.

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

For the six months ended June 30, 2002, net cash used in operations was $511,000 compared to $7.5 million provided by operating activities in 2001. Net cash provided by operations prior to changes in working capital for the six months ended June 30, 2002 was $2.3 million compared to $6.7 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 six months ended June 30, 2002, net cash used in investing activities was $4.8 million compared to $5.2 million in 2001. For the six months ended June 30, 2002, net cash provided by financing activities was $5.3 million compared to $2.3 million used in financing activities in 2001. For the six months ended June 30, 2002, the Company spent approximately $1.3 million in the United States primarily to fund development and exploration activities in the Piceance Basin and approximately $3.5 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 six months ended June 30, 2001, the Company spent approximately $7.7 million in the United States primarily to fund development and exploration activities in the Permian and Piceance Basins. The Company also 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 six months ended June 30, 2001, the Company spent $4.0 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 June 30, 2002, the Company had no cash balances as all available cash is used to pay down the Company's long-term debt and working capital deficit. The Company anticipates that capital expenditures for the remainder 2002, exclusive of acquisitions or divestitures which may occur subsequent to June 30, 2002, to be approximately $3.5 million. Carbon believes that available borrowings under its credit agreements and projected operating cash flows will be sufficient to cover its working capital, planned capital expenditures, and debt service requirements for the next 12 months. Carbon is currently in discussions regarding possible acquisitions of oil and gas properties in Alberta, Canada, which if consummated, would require significant additional financing. There is no assurance that any such transaction will be completed or whether any financing can be accomplished on terms that are acceptable to the Company.

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

The table below sets forth the Company's contractual obligations at June 30, 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 facility	$	$ 4,476	$ 17,872
Operating leases/management agreements	683	656	
	$ 683	$ 5,132	$ 17,872

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 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 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. For purposes of calculating the ceiling test at June 30, 2002, the Company used mainline prices of $1.10/mmbtu in Colorado and Utah and $1.43/mmbtu in Central Alberta. The negative differential of these prices when compared to a U.S. reference price set at Henry Hub at June 30, 2002, was $2.32/mmbtu for Colorado and Utah and $1.99/mmbtu for Central Alberta. This compares to a 36 month historical negative differential of $.37/mmbtu for Colorado and Utah and $.29/mmbtu for Central Alberta. Due to these large pricing differentials when compared to a U.S. reference price set at Henry Hub 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 is 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. Accordingly, 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 are included as additional accumulated DD&A in the accompanying balance sheet. 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

The Company is exposed to interest rate risk. Interest rate risk is estimated as the potential change in the fair value of interest sensitive investments resulting from an immediate hypothetical change in interest rates. The sensitivity analysis presents the change in fair value of these instruments and changes in the Company's earnings and cash flows assuming an immediate one percent change in floating interest rates. At June 30, 2002, the Company had $17.7 million of floating rate debt through its facility with Wells Fargo and $5.5 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 July 1, 2002, from a one percent change in interest rates would be approximately $132,000 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 as well as regional supply and demand. Worldwide political events can also impact commodity prices. The Company may use certain financial instruments including swaps, collars, futures and other contracts in an attempt to reduce exposure to the market fluctuations in the price of oil and natural gas. 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. Hedging is subject to a number of risks, including credit risk of the counterparty to the hedge. For additional information, see Note 2 to the Consolidated Financial Statements in this report. In addition, quantitative and qualitative disclosures about market risk were included in the Company's Form 10-K (Item 7A) and the financial statements included therein for the fiscal year ended December 31, 2001.

PART II OTHER INFORMATION

Item 1-2 Not applicable.

Item 3 Please see information on Carbon's U.S. Credit Facility contained in Note 4 of Notes to Consolidated Financial Statements in this report, which information is incorporated herein by reference, regarding the non-compliance and subsequent amendment (where the Company is in compliance) of a covenant regarding the maintenance of a certain tangible net worth level.

Item 4 On June 13, 2002, the Company held its 2002 Annual Meeting of Shareholders. At that meeting, the six existing directors were nominated and re-elected as directors of the Company. The six persons constitute all members of the Board of Directors of the Company. These directors and the votes for and withheld for each of them were as follows:

	For	**Withheld**	**Broker Non-Votes**
Patrick R. McDonald	6,076,749		
Cortlandt S. Dietler	6,076,749		
David H. Kennedy	6,076,749		
Bryan H. Lawrence	6,076,749		
Peter A. Leidel	6,076,749		
Harry A. Trueblood, Jr.	6,076,749		

Item 5 Not applicable.

Item 6 (a) Exhibits

10.1 Credit agreement dated as of May 9, 2002 between CEC Resources Ltd. and Canadian Imperial Bank of Commerce *

99 Section 906 Certification*

(b) Reports on Form 8-K

(i) A report on Form 8-K, filed with the Securities and Exchange Commission on July 12, 2002, regarding changes in the Company's independent public accountants.

(ii) A report on Form 8-K/A, filed with the Securities and Exchange Commission on July 25, 2002, regarding changes in the Company's independent public accountants.

* 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: August 19, 2002 By: /s/ Patrick R. McDonald

President and Chief Executive Officer

Date: August 19, 2002 By: /s/ Kevin D. Struzeski

Treasurer and Chief Financial Officer

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