CARBON ENERGY CORP
Form 10-Q
May 15, 2002

Use these links to rapidly review the document
CARBON ENERGY CORPORATION INDEX

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2002

Or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15() 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 May 8, 2002
Common stock, no par value	6,133,424 shares

CARBON ENERGY CORPORATION

INDEX

PART I FINANCIAL INFORMATION

Consolidated Balance Sheets as of March 31, 2002 and December 31, 2001

Consolidated Statements of Operations for the Three Months Ended March 31, 2002 and 2001

Consolidated Statement of Stockholders' Equity for the Three Months Ended March 31, 2002

Consolidated Statements of Cash Flows for the Three Months Ended March 31, 2002 and 2001

Notes to Consolidated Financial Statements

Management's Discussion and Analysis of Financial Condition and Results of Operations

Quantitative and Qualitative Disclosure about Market Risk

PART II OTHER INFORMATION

PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

CARBON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
(in thousands)

	March 31, 2002	December 31, 2001
	(unaudited)	
ASSETS		
Current assets:		
Cash	$	$
Accounts receivable, trade	2,405	2,258
Accounts receivable, other	29	53
Prepaid expenses and other	577	317

	March 31, 2002	December 31, 2001
Current derivative asset	112	341
Total current assets	3,123	2,969
Property and equipment, at cost:		
Oil and gas properties, using the full cost method of accounting:		
Unproved properties	7,885	7,500
Proved properties	63,997	62,750
Furniture and equipment	923	927
	72,805	71,177
Less accumulated depreciation, depletion and amortization	(13,962)	(12,226)
Property and equipment, net	58,843	58,951
Deposits and other long-term assets	502	448
Total assets	$ 62,468	$ 62,368

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

CARBON ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS
(in thousands)

	March 31, 2002	December 31, 2001
	(unaudited)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 2,913	$ 5,113
Accrued production taxes payable	396	527
Income taxes payable		1,168
Undistributed revenue and other	986	1,062
Current derivative liability	806	76
Deferred income taxes		74
Total current liabilities	5,101	8,020
Long-term debt	22,348	17,870
Other long-term liabilities	11	18

	March 31, 2002	December 31, 2001
Deferred income taxes	2,185	2,577
Minority interest	29	29
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 6,090,183 shares and 6,079,225 shares outstanding at March 31, 2002 and December 31, 2001, respectively	31,857	31,799
Retained earnings	2,006	2,538
Accumulated other comprehensive loss	(1,069)	(483)
Total stockholders' equity	32,794	33,854
Total liabilities and stockholders' equity	$ 62,468	$ 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 March 31,	
	2002	2001
Revenues:		
Oil and gas sales	$ 3,548	$ 7,616
Marketing and other, net	78	687
	3,626	8,303
Expenses:		
Oil and gas production costs	1,185	1,368
Depreciation, depletion and amortization	1,740	1,388
General and administrative, net	1,329	1,096
Interest, net	193	186
Total operating expenses	4,447	4,038
Minority interest		22
Income (loss) before income taxes	(821)	4,243
Income tax provision (benefit):		
Current	27	719
Deferred	(316)	998

	Three Months Ended March 31,	
Total taxes	(289)	1,717
Net income (loss) before cumulative effect of change in accounting principle	(532)	2,526
Cumulative effect of change in accounting principle, net of tax		(1,510)
Net income (loss)	$ (532)	$ 1,016
Average number of common shares outstanding:		
Basic	6,086	6,026
Diluted	6,086	6,246
Earnings (loss) per share basic:		
Net income (loss) before cumulative effect of change in accounting principle	$ (0.09)	$ 0.42
Cumulative effect of change in accounting principle, net of tax		(0.25)
	$ (0.09)	$ 0.17
Earnings (loss) per share diluted:		
Net income (loss) before cumulative effect of change in accounting principle	$ (0.09)	$ 0.40
Cumulative effect of change in accounting principle, net of tax		(0.24)
	$ (0.09)	$ 0.16

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

CARBON ENERGY CORPORATION

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY
For the Three Months Ended March 31, 2002
(in thousands)
(unaudited)

	Common Stock		Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total
	Shares	Amount			
Balances, December 31, 2001	6,079	$ 31,799	$ 2,538	$ (483)	$ 33,854
Comprehensive income:					
Net income			(532)		(532)
Currency translation adjustment				(6)	(6)
Reclassification adjustment for settled contracts				92	92

	Common Stock		Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	
Changes in fair value of outstanding hedge positions				(640)	(640)
Impaired oil and gas hedging swaps				(32)	(32)
Total comprehensive income					(1,118)
Common stock issued	5	25			25
Vesting of restricted stock grants	6	33			33
Balances, March 31, 2002	6,090	$ 31,857	$ 2,006	$ (1,069)	$ 32,794

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 Three Months Ended March 31,	
	2002	**2001**
Cash flows from operating activities:		
Net income (loss)	$ (532)	$ 1,016
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization expense	1,740	1,388
Non cash settlement of derivative contracts	(51)	
Deferred income tax	(316)	998
Cumulative effect of change in accounting principle		1,510
Minority interest		22
Vesting of restricted stock grants	33	30
Changes in operating assets and liabilities:		
Decrease (increase) in:		
Accounts receivable	908	(1,222)
Amounts due from broker		1,408
Employee trust		51
Prepaid expenses and other assets	6	330
Increase (decrease) in:		
Accounts payable and accrued expenses	(2,811)	(1,674)
Undistributed revenue	(74)	465
Net cash provided by (used in) operating activities	(1,097)	4,322

	For the Three Months Ended March 31,	
Cash flows from investing activities:		
Capital expenditures for oil and gas properties	(2,440)	(6,335)
Proceeds from property sale	1	6,758
Acquisition of CEC Resources		(203)
Capital expenditures for support equipment		(24)
Net cash provided by (used in) investing activities	(2,439)	196
Cash flows from financing activities:		
Proceeds from note payable	8,549	19,227
Principal payments on note payable	(4,069)	(23,745)
Proceeds from issuance of common stock	24	36
Net cash provided by (used in) financing activities	4,504	(4,482)
Effect of exchange rate changes on cash		(57)
Net increase (decrease) in cash	968	(21)
Cash, beginning of period	(968)	21
Cash, end of period	$	$
Supplemental cash flow information:		
Cash paid for interest	$ 197	$ 255
Cash paid for taxes	1,236	263

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 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 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. Collectively, Carbon, CEC, BFC 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 March 31, 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% of the equity. All significant intercompany transactions and balances have been eliminated.

Cash Equivalents The Company considers all highly 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 the estimated production of proved oil and gas reserves discounted at 10%, using constant oil and gas prices in effect at the end of the reporting period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair market value of unproved properties included in the costs being amortized, if any; less related income tax effects. The capitalized costs reflected in the accompanying financial statements do not exceed this limitation.

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.

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 is more (overproduced) or less (underproduced) than the volumes to which the Company is entitled based on its interests in its properties, a gas imbalance has been created. Where the estimated remaining reserves on 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. 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 ended March 31, 2002 and 2001 (in thousands):

	United States Three Months Ended March 31,		Canada Three Months Ended March 31,	
	2002	2001	2002	2001
Oil	$	$	$ 11	$
Natural gas	51	(529)	95	(720)

The table below sets forth the Company's fixed price positions relating to its natural gas and oil production at March 31, 2002:

Fixed price:

BFC 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)
			(thousands)				(thousands)
Gas				**Gas**			
04/01/02-12/31/02	917,000	$ 2.47	$ (570)	04/01/02-12/31/02	679,000	$ 2.42	$ 18
01/01/03-06/30/03	180,500	2.82	(129)	01/01/03-12/31/03	216,000	2.81	27
Oil							
04/01/02-12/31/02	27,500	$ 24.55	$ (15)				
01/01/03-03/31/03	9,000	24.55	3				

The Company utilizes financial instruments known as collars that establish a floor and ceiling price. The table below sets forth the Company's natural gas and oil collars in place at March 31, 2002:

Collars:

CEC Contracts				
Time Period	Bbl/ MMBtu	Average Floor Bbl/ MMBtu	Average Ceiling Bbl/ MMBtu	Derivative Asset/ (Liability)
				(thousands)
Gas				
04/01/02-10/31/02	203,000	$ 2.40	$ 3.38	$ 22
Oil				
04/01/02-12/31/02	27,500	$ 22.00	$ 27.50	$ 17

On January 1, 2001, the Company adopted the provisions of 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.

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 quarter of 2002, net hedging gains of $157,000 ($92,000 after tax) were transferred from other comprehensive income to earnings, and the change in the fair market value of outstanding derivative contracts designated as hedges decreased by $1.0 million ($600,000 after tax). As the underlying prices in the Company's hedge contracts were consistent with the indices used to sell their oil and gas, no ineffectiveness was recognized related to its hedge commitments in the first quarter of 2002. As of March 31, 2002, the Company had net unrealized derivative losses of $654,000 ($410,000 after tax). Based on futures prices as of March 31, 2002, the Company expects to reclassify $695,000 of these net unrealized losses to earnings during the next twelve month period.

Interest Rate Swap Agreements During the first quarter of 2002, the Company entered into interest rate swap agreements that effectively convert a portion its variable rate borrowings in the United States to fixed rate debt for periods of up to two years, thus reducing the impact of interest rate changes on future income. The table below sets forth the Company's interest rate derivative contracts in place at March 31, 2002:

	Notational Amount	Contract Expiration Date	LIBOR Fixed Rate	All-In LIBOR Fixed Rate		Derivative Asset/ (Liability)
	(thousands)					(thousands)
$	3,700	May 2003	3.46%	5.21%	$	(7)
	2,000	October 2003	3.77%	5.52%		(6)
	800	October 2003	3.82%	5.57%		(3)
	1,000	March 2004	4.15%	5.90%		(3)
	2,500	April 2004	4.24%	5.99%		(7)

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 uses 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 losses of $6,000 and $378,000 for the three months ended March 31, 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 and classified as other comprehensive income. The following table sets forth the calculation of comprehensive income for the three months ended March 31, 2002 and 2001:

	Three Months Ended March 31,			
		2002		2001
	(in thousands)			
Net income	$	(532)	$	1,016

	Three Months Ended March 31,	
Other comprehensive income (loss), net of tax:		
Currency translation adjustment	(6)	(378)
Cumulative effect of change in accounting principle January 1, 2001		(2,768)
Reclassification adjustment for settled contracts	92	727
Changes in fair value of outstanding hedge positions	(640)	516
Impairment of oil and gas hedging swaps	(32)	
Other comprehensive income (loss)	(586)	(1,903)
Comprehensive income	$ (1,118)	$ (887)

The impairment of oil and gas hedging swaps related to a fourth quarter 2001 non-cash provision of $246,000 ($153,000 after tax) with Enron North America (Enron). In accordance with generally accepted accounting principles, the Company recorded non-cash revenues of $51,000 during the first quarter of 2002, with an additional $195,000 to be recorded during the course of 2002 as these hedges would have expired.

Earnings (Loss) Per Share The Company uses the weighted average number of shares outstanding to calculate earnings per share data. When dilutive, options are included as share equivalents using the treasury stock method and are included in the calculation of diluted per share data. Due to the Company's net loss for the three months ended March 31, 2002, basic and diluted earnings per share are the same, as the assumed conversion of 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 has not yet determined the impact of adoption of this statement.

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) and had a borrowing base of $20.0 million with outstanding borrowings of $17.9 million at March 31, 2002. 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. The Company is currently in negotiations with Wells Fargo to extend the revolving phase of the facility. However, there can be no guarantee that the Company will be able to successfully negotiate such an extension. The 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. Subject to possible changes in the borrowing base, Wells Fargo has agreed that it will not require the Company to make any principal payments under the term loan section of the facility until April 2003 at the earliest. As such, no amounts under the Wells Fargo facility have been classified as current on the March 31, 2002 balance sheet. 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 average borrowing rate was approximately 3.7% at March 31, 2002. The borrowing base is based upon the lender's evaluation of the Company's proved oil and gas reserves, generally determined semi-annually.

The credit agreement contains various 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 Credit Facility The Company's credit facility is an oil and gas reserve based line-of-credit with Canadian Imperial Bank of Commerce (CIBC) and had a borrowing base of $9.0 million with outstanding borrowings of $4.5 million at March 31, 2002. The Canadian facility is secured by the Canadian oil and gas properties of the Company. The revolving phase of the Canadian facility expired on March 31, 2002. The Company is currently in negotiations with CIBC to extend the revolving phase to April 1, 2003. However, there can be no guarantee that the Company will be able to successfully negotiate such an extension. 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 April 2003 at the earliest. As such, no amounts under the CIBC facility have been classified as current on the March 31, 2002 balance sheet. The Canadian facility bears interest at the CIBC Prime rate plus .5%. The Company's borrowing rate was 4.25% at March 31, 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. 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: BFC 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 months ended March 31, 2002 and 2001 was prepared on the same basis as Carbon's consolidated financial statements.

	Three Months Ended March 31, 2002			Three Months Ended March 31, 2001		
	United States	Canada	Total	United States	Canada	Total
Revenues:						
Oil and gas sales	$ 1,899	$ 1,649	$ 3,548	$ 3,801	$ 3,815	$ 7,616
Marketing and other, net	78		78	687		687

	Three Months Ended March 31, 2002			Three Months Ended March 31, 2001		
	1,977	1,649	3,626	4,488	3,815	8,303
Expenses:						
Oil and gas production costs	769	416	1,185	843	525	1,368
Depreciation, depletion and amortization	1,082	658	1,740	737	651	1,388
General and administrative, net	878	451	1,329	620	476	1,096
Interest, net	163	30	193	132	54	186
Total operating expenses	2,892	1,555	4,447	2,332	1,706	4,038
Minority interest					22	22
Income (loss) before income taxes	(915)	94	(821)	2,156	2,087	4,243
Income tax provision (benefit)	(343)	54	(289)	809	908	1,717
Net income (loss) before cumulative effect of change in accounting principle	(572)	40	(532)	1,347	1,179	2,526
Cumulative effect of change in accounting principle, net of tax				(1,510)		(1,510)
Net income (loss)	$ (572)	$ 40	$ (532)	$ (163)	$ 1,179	$ 1,016
Total assets	$ 42,675	$ 19,793	$ 62,468	$ 39,496	$ 18,539	$ 58,035

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, production volumes, average sales prices, expenses and the percentage change between periods for the three months ended March 31, 2002 and 2001 (first quarter) for the Company's United States and Canadian operations.

All amounts are presented in U.S. dollars.

	United States Three Months Ended March 31,			Canada Three Months Ended March 31,		
	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	$ 1,899	$ 3,801	-50%	$ 1,649	$ 3,815	-57%
Marketing and other, net	78	687	-89%			n/a
Total revenues	$ 1,977	$ 4,488	-56%	$ 1,649	$ 3,815	-57%
Daily production volumes:						

	United States Three Months Ended March 31,			Canada Three Months Ended March 31,		
Natural gas (MMcf)	9.1	6.7	36%	6.2	6.9	-10%
Oil and liquids (Bbl)	247	239	3%	155	171	-9%
Equivalents production (MMcfe 6:1)	10.6	8.1	31%	7.1	7.9	-10%
Average price realized:						
Natural gas (Mcf)	$ 1.84	$ 5.23	-65%	$ 2.56	$ 5.44	-53%
Oil and liquids (Bbl)	17.91	28.97	-38%	15.58	28.15	-45%
Direct lifting costs	$ 386	$ 290	33%	$ 349	$ 511	-32%
Average direct lifting costs/Mcfe	0.41	0.39	5%	0.54	0.72	-25%
Other production costs	383	553	-31%	67	14	n/a
General and administrative, net	878	620	42%	451	476	-5%
Depreciation, depletion and amortization	1,082	737	47%	658	651	1%
Interest expense, net	163	132	23%	30	54	-44%
Income tax provision	(343)	809	-142%	54	908	-94%

Revenues from oil and gas sales of BFC for the first quarter of 2002 were $1.9 million, a 50% 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 quarter of 2002 were $1.6 million, a 57% 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 quarter of 2002 was 247 barrels of oil and liquids per day and 9.1 million cubic feet (MMcf) of gas per day, an increase of 31% 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 quarter of 2002, BFC participated in the drilling of two gross (.1 net) oil wells compared to two gross (.5 net) oil wells, five gross (3.4 net) gas wells and two gross (1.4 net) unsuccessful wells during the first quarter of 2001.

Average production in Canada for the first quarter of 2002 was 155 barrels of oil and liquids per day and 6.2 MMcf of gas per day, a decrease of 10% on a Mcfe basis from the same period in 2001. The decrease was primarily due to comparatively large first quarter 2001 production volumes 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 successful drilling activities in the Carbon and Rowley areas of Central Alberta. During the first quarter of 2002, CEC participated in the drilling of two gross (1.5 net) gas wells and one gross (.5 net) unsuccessful well compared to three gross (3.0 net) gas wells during the first quarter of 2001.

Average oil and liquids prices realized by BFC decreased 38% from $28.97 per barrel for the first quarter of 2001 to $17.91 for 2002. Average natural gas prices realized by BFC decreased 65% from $5.23 per Mcf for the first quarter of 2001 to $1.84 for 2002. The average natural gas price includes hedge losses of $529,000 for the first quarter of 2001 compared to hedge gains of $51,000 for 2002. The Company's estimated average price on March 31, 2002 for natural gas and oil and liquids was $2.54 per Mcf and $23.82 per barrel, respectively.

Average oil and liquids prices realized by CEC decreased 45% from $28.15 per barrel for the first quarter of 2001 to $15.58 for 2002. The average oil price includes hedge gains of $11,000 for the first quarter of 2002. There was no oil hedge activity for the first quarter of 2001. Average natural gas prices realized by CEC decreased 53% from $5.44 per Mcf for the first quarter of 2001 to $2.56 for 2002. The average natural gas price includes hedge losses of $720,000 for the first quarter of 2001 compared to hedge gains of $95,000 for 2002. The Company's estimated average price on March 31, 2002 for natural gas and oil and liquids was $2.73 per Mcf and $23.20 per barrel, respectively.

Marketing and other revenues in the United States were $78,000 for the first quarter of 2002 compared to $687,000 for 2001. First quarter 2001 results were primarily due to mark to market gains of $621,000 related to a derivative contract that no longer qualified for hedge accounting treatment upon the January 1, 2001 adoption of 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. The Company has reduced its efforts concerning the marketing of third party natural gas and anticipates that natural gas trading activities will continue to decline significantly in 2002 compared to 2001 and prior years.

Direct lifting costs incurred by BFC were $386,000 or $.41 per Mcfe for the first quarter of 2002 compared to $290,000 or $.39 per Mcfe for 2001.

Other production costs incurred by BFC, consisting primarily of severance taxes and production overhead, were $383,000 for the first quarter of 2002 compared to $553,000 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 $349,000 or $.54 per Mcfe for the first quarter of 2002 compared to $511,000 or $.72 per Mcfe for 2001. The higher per Mcfe expense in the first quarter of 2001 was primarily due to higher chemical costs related to the Company's initial production and a prior period charge for gas processing fees.

Other production costs incurred by CEC, consisting primarily of severance taxes, were $67,000 for the first quarter of 2002 compared to $14,000 for 2001. The increase was primarily due to increased production during the first quarter of 2002 from wells subject to these taxes.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by BFC increased 42% from $620,000 for the first quarter of 2001 to $878,000 for 2002. The increase was primarily due to legal expenses incurred of $146,000 related to the case of Bonneville Fuels Corporation vs. Williams Production RMT Company, which proved unsuccessful. For more information regarding this case, see Part II, Item 1, to the Form 10-Q.

General and administrative expenses (net of overhead reimbursements on operated wells) incurred by CEC decreased 5% from $476,000 for the first quarter of 2001 to $451,000 for 2002.

Interest expense incurred by BFC increased 23% from $132,000 for the first quarter of 2001 to $163,000 for 2002. The increase was due primarily to increased average debt balances in the first quarter of 2002 relative to 2001, partially offset by a decline in interest rates.

Interest expense incurred by CEC decreased 44% from $54,000 for the first quarter of 2001 to $30,000 for 2002. The decrease was due primarily to a decline in interest rates, partially offset by increased average debt balances in the first quarter 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 BFC and CEC and the volume of proved reserves the Company acquired in the acquisitions.

DD&A expense incurred by BFC was $1.1 million or $1.14 per Mcfe for the first quarter of 2002 compared to $737,000 or $1.00 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 BFC.

DD&A expense incurred by CEC was $658,000 or $1.02 per Mcfe compared to $651,000 or $.91 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.

Income tax benefit recorded by BFC was $343,000 for the first quarter of 2002, an effective tax rate of 38% compared to an expense of $809,000 and an effective tax rate of 38% for 2001.

Income tax expense incurred by CEC was $54,000 for the first quarter of 2002, an effective tax rate of 57% compared to $908,000 and an effective tax rate of 44% for 2001.

Liquidity and Capital Resources

At March 31, 2002, the Company had $62.5 million of assets. Total capitalization was $55.1 million, consisting of 59% of stockholders' equity and 41% of debt.

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

For the three months ended March 31, 2002, net cash used in operations was $1.1 million compared to $4.3 million provided by operations in 2001. Net cash provided by operations prior to changes in working capital for the three months ended March 31, 2002 was $874,000 compared to $5.0 million in 2001. The decrease in operating cash flow was primarily due to sharp declines in oil, liquids, and natural gas prices, partially offset by increased oil, liquids and natural gas production.

For the three months ended March 31, 2002, net cash used in investing activities was $2.4 million compared to $196,000 provided by investing activities in 2001. For the three months ended March 31, 2002, net cash provided by financing activities was $4.5 million compared to $4.5 million used in financing activities in 2001. For the three months ended March 31, 2002, the Company spent approximately $700,000 in the United States primarily to fund development and exploration activities in the Piceance Basin and approximately $1.7 million in Canada primarily to fund development and exploration activities in the Carbon area of Central Alberta. For the three months ended March 31, 2001, the Company spent approximately $3.8 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 three months ended March 31, 2001, the Company spent $2.8 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 March 31, 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, exclusive of acquisitions (if any) or divestitures in 2002 will be approximately $6.7 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. Nevertheless, Carbon may explore outside funding opportunities including equity or additional debt financings for use in expanding Carbon's operations or in consummating any significant acquisitions. Carbon does not know, however, 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 and 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 March 31, 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	$	$ 17,880	$ 4,468
Operating leases / management agreements	683	656	
	$ 683	$ 18,536	$ 4,468

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 Polices

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 the estimated production of proved oil and gas reserves discounted at 10% using constant oil and gas prices in effect at the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair market value of unproved properties included in the cost being amortized, if any; less related income tax effects. The capitalized costs reflected in the accompanying financial statements do not exceed this limitation.

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 3 to 7 years.

Derivative Instrument and Hedging Activities 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 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. Gain 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 market value which is determined by using market pricing. 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 March 31, 2002, the Company had $17.9 million of floating rate debt through its facility with Wells Fargo and $4.5 million through its facility with CIBC. In addition, the Company currently has interest rate swap agreements that effectively converts 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 April 1, 2002, from a one percent change in interest rates would be approximately $124,000 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.

Inflation and Changes in Prices

Changing prices, or a change in the dollar's purchasing power, distorts the traditional measures of financial performance which are generally expressed in terms of the actual number of dollars exchanged and do not take into account changes in the purchasing power of the monetary units. This results in the reporting of many transactions over an extended period as though the dollars received or expended were of common value, which does not accurately portray financial performance.

Inflation, as well as a recessionary period, can cause significant swings in the interest rates that companies pay on bank borrowings. These factors are anticipated to continue to affect the Company's operations both positively and negatively for the foreseeable future.

Expenses and costs in the oil and gas industry are affected by the overall level of inflation in the economy and price and economic conditions specific to the oil and gas industry, including the effects caused by higher or lower oil and gas prices. Although it is difficult to determine the future prices of oil and natural gas, price fluctuations may have a material effect on the Company.

PART II OTHER INFORMATION

Item 1 The Company was the plaintiff in Bonneville Fuels Corporation vs. Williams Production RMT Company, brought in District Court of Garfield County, Colorado. Bonneville claimed oil and gas leasehold interests reserved pursuant to an assignment between Bonneville and a third party, subsequently acquired by Williams Production RMT Company. Bonneville also sought damages for breach of the operating agreement governing the lands in question. On March 7, 2002, the Court denied Bonneville's claims. Total expenses incurred in this litigation from inception through March 31, 2002 is approximately $390,000, of which $244,000 was incurred during 2001 ($6,000 in the first quarter of 2001) with the balance of $146,000 recorded in the first quarter of 2002.

Item 2 During the quarter ended March 31, 2003, the Company granted 17,500 shares of its stock under its restricted stock plan to its executive officers and to senior officers of its subsidiaries. The Company believes that these grants did not constitute sales under the Securities Act of 1933. These grants would also be exempt under Section 4(2) of the Securities Act of 1933 in Rule 506 of Regulation D if considered a sale.

Item 3 - 5 Not applicable

Item 6
(a) Exhibits

(b) No reports on Form 8-K were filed by the registrant during the quarter ended March 31, 2002.

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: May 15, 2002 By: /s/ PATRICK R. MCDONALD

President and Chief Executive Officer

Date: May 15, 2002 By: /s/ KEVIN D. STRUZESKI

Treasurer and Chief Financial Officer

yle="DISPLAY: inline; FONT-SIZE: 10pt; MARGIN-LEFT: 0px; TEXT-INDENT: 0px; MARGIN-RIGHT: 0px; FONT-FAMILY: Times New Roman">$

0.09

Discontinued operations

(—
)

(0.01
)

$
(.04
)
$
0.08

Weighted average shares outstanding

10,076

10,076

Diluted income (loss) per share of common stock

Continuing operations

$
(.04
)
$
0.09

Discontinued operations

(—
)

(0.01
)

$
(.04
)
$
0.08

Weighted average shares outstanding

10,076

10,103

See accompanying notes to unaudited consolidated financial statements.

PORTA SYSTEMS CORP. AND SUBSIDIARIES
Unaudited Consolidated Statements of Cash Flows
(In thousands)

	Nine Months Ended	
	September 30, 2007	September 30, 2006
Cash flows from operating activities of continuing operations:		
Net income (loss)	$ (1,052)	$ 2,009
Loss from discontinued operations	521	245
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities of continuing operations:		
Depreciation and amortization	281	193
Changes in operating assets and liabilities:		
Accounts receivable	(18)	(2,883)
Inventories	(1,346)	625
Prepaid expenses and other current assets	209	(349)
Other assets	—	4
Accounts payable, accrued expenses and other liabilities	240	2,879
Net cash (used in) provided by continuing operations	(1,165)	2,723
Net cash used in operations of discontinued operations	(87)	(1,406)
Net cash (used in) provided by operating activities	(1,252)	1,317
Cash flows from investing activities:		
Capital expenditures, net	(304)	(149)
Net cash used in investing of discontinued operations	—	(184)
Net cash used in investing activities	(304)	(333)
Cash flows from financing activities:		
Increase in senior debt	—	154
Repayments of senior debt	(140)	(1,013)
Net cash used in financing activities	(140)	(859)
Effect of exchange rate changes on cash	(10)	(24)
Increase (decrease) in cash and cash equivalents	(1,706)	101
Cash and cash equivalents - beginning of the year	2,102	1 ,254
Cash and cash equivalents - end of the period	$ 396	$ 1,355
Supplemental cash flow disclosure:		
Cash paid for interest expense	$ 568	$ 159
Cash paid for income taxes	$ —	$ 74

See accompanying notes to unaudited consolidated financial statements.

PORTA SYSTEMS CORP. AND SUBSIDIARIES
NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

Note 1: Management's Responsibility For Interim Financial Statements Including AllAdjustments Necessary For Fair Presentation

Management acknowledges its responsibility for the preparation of the accompanying interim consolidated financial statements which reflect all adjustments, consisting of normal recurring adjustments, considered necessary in its opinion for a fair statement of its consolidated financial position and the results of its operations for the interim period presented. These consolidated financial statements should be read in conjunction with the summary of significant accounting policies and notes to consolidated financial statements included in the Company's Form 10-K annual report for the year ended December 31, 2006. These financial statements have been prepared assuming that the Company will continue as a going concern and, accordingly, do not include any adjustments that might result from the outcome of the uncertainties described within. The audit opinion included in the December 31, 2006 Form 10-K annual report contained an explanatory paragraph regarding the Company's ability to continue as a going concern. The factors which resulted in the explanatory paragraph are continuing. Results for the third quarter or the first nine months of 2007 are not necessarily indicative of results for the year.

Note 2: Inventories

Inventories are stated at the lower of cost (on the average or first-in, first-out method) or market. The composition of inventories at the end of the respective periods is as follows (net of reserve of $1,953,000 for 2007 and $2,345,000 for 2006):

	September 30, 2007		December 31, 2006	
	(In thousands)			
Parts and components	$	3,535	$	3,637
Work-in-process		1,096		543
Finished goods		1,345		411
	$	5,976	$	4,591

Note 3: Senior and Subordinated Debt

On September 30, 2007, the Company's liability to its senior debt holder was $23,373,000 plus accrued interest of $312,000. During the fourth quarter of 2004, SHF IX LLC, an affiliate of Stonehill Financial, LLC, purchased the Company's senior debt of approximately $25,000,000 from Wells Fargo Foothill, Inc. The Company has made payments through September 30, 2007 totaling $2,876,000 as required by amendments and extensions of the loan agreement, of which $659,000 was applied to interest and $2,217,000 was applied to principal. On February 7, 2007 Cheyne Special Situations Fund L.P ("Cheyne") purchased the Company's senior debt of approximately $23,400,000 from SHF IX, LLC and subsequently extended the maturity of the senior debt to February 1, 2008. Through September 30, 2007, the Company had made interest payments of approximately $493,000 to Cheyne. The Company can not give any assurance that the holder of its senior debt will extend the loan beyond February 1, 2008. Any adverse event, including declines in business, could have an effect on the decision of the senior debt holder to extend or demand payment on the notes. If the senior debt holder does not extend the maturity of the Company's senior debt beyond February 1, 2008 or if the senior debt holder demands payment of all or a significant portion of the senior debt when due, the Company will not be able to continue in business, and it is likely that it will seek protection under the Bankruptcy Code. See Note 8 regarding additional loans to the Company, subsequent to September 30, 2007.

As of September 30, 2007, the Company's short-term debt also included $6,144,000 principal amount of subordinated notes that became due on July 3, 2001 and $385,000 principal amount of 6% debentures which became due on July 2, 2002. The interest rate on the 6% debentures increased to 8.26% as a result of our failure to make interest payments on the debentures since July 1, 2000 and our failure to pay principal on July 2, 2002. The interest rate on the subordinated note increased to 15% as a result of our failure to pay the subordinated notes when due on July 3, 2001. Accrued interest on the subordinated notes and the 6% debentures was approximately $6,844,000, which represents interest through September 30, 2007. We are precluded by our senior debt holder from paying any principal or interest on the subordinated debt.

Note 4: Accounting for Stock Based Compensation

For the nine months ended September 30, 2007, the Company issued nonqualified stock options to purchase 20,000 shares of common stock under its 1999 Plan that provides for the automatic grant to non-management directors. This Plan provides for the automatic grant to non-management directors of non-qualified options to purchase 5,000 shares on May 1st of each year commencing May 1, 1999, based upon the average closing price of the last ten trading days of April of each year. Options under this Plan have a term of 10 years. The Company uses the Black-Scholes valuation model and straight-line amortization of compensation expense over the requisite service period when granting stock options. All options previously granted are fully vested. Based on the Black-Scholes valuation model there is no non-cash compensation expense attributable to stock options granted during the quarters. Stock compensation expense for all vested options to date is diminutive.

Note 5: Segment Data

The Company has two reportable segments: Line Connection and Protection Equipment ("Line") whose products interconnect copper telephone lines to switching equipment and provide fuse elements that protect telephone equipment and personnel from electrical surges, and Signal Processing ("Signal") whose products are used in data communication devices that employ high frequency transformer technology.

The Company formerly had a third reportable segment - Operating Support Systems ("OSS"), which was engaged in the business of marketing, manufacturing and selling products that automated the testing, provisioning, maintenance and administration of communication networks and the management of support personnel and equipment. Due to continuing losses in the OSS division, combined with difficulties in marketing OSS products in view of the Company's financial condition, the Company decided in December 2003 that it would discontinue this operating segment. As a result, the Company limited the OSS activities to the performance of contractual maintenance and warranty services through June 2007 (see Note 7). Accordingly, as of June 30, 2007, the net assets of $434,000 of this operation were written off and the results of operations of the OSS division have been segregated and reported separately as discontinued operations on the consolidated financial statements in this Form 10-Q.

The factors used to determine the above segments focused primarily on the types of products and services provided, and the type of customer served. Each of these segments is managed separately from the others, and management evaluates segment performance based on operating income.

There has been no significant change, from December 31, 2006, in the basis of measurement of segment revenues and profit or loss, and no significant change in the Company's assets for the Line and Signal reporting segments.

	Nine Months Ended		Three Months Ended	
	September 30, 2007	September 30, 2006	September 30, 2007	September 30, 2006
Sales:				
Line	$ 18,228,000	$ 21,308,000	$ 5,594,000	$ 7,694,000
Signal	3,694,000	3,731,000	1,057,000	1,324,000
Total of Continuing Operations	$ 21,922,000	$ 25,039,000	$ 6,651,000	$ 9,018,000
Segment profit:				
Line	$ 2,383,000	$ 3,956,000	$ 637,000	$ 1,341,000
Signal	933,000	1,067,000	235,000	462,000
Total of Continuing Operations	$ 3,316,000	$ 5,023,000	$ 872,000	$ 1,803,000

The following table reconciles segment totals to consolidated totals:

Operating income (loss):				
Total segment income for reportable segments	$ 3,316,000	$ 5,023,000	$ 872,000	$ 1,803,000
Corporate and unallocated	(2,260,000)	(1,831,000)	(740,000)	(615,000)
Consolidated total operating income	$ 1,056,000	$ 3,192,000	$ 132,000	$ 1,188,000

Note 6: <u>New accounting pronouncements</u>

In June 2006, the FASB issued Interpretation No. 48 (“FIN 48”), Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109. The objective of this interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 is effective for the fiscal years beginning after December 15, 2006. The adoption of this statement did not have an effect on our financial position or results of operations.

In September 2006, FASB issued SFAS No. 157, “Fair Value Measurements,” which provides enhanced guidance for using fair value to measure assets and liabilities. SFAS No. 157 establishes a common definition of fair value, provides a framework for measuring fair value under U.S. GAAP and expands disclosures requirements about fair value measurements. SFAS No. 157 is effective for financial statements issued in fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The adoption of this statement is not expected to have a material effect on our financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" or SFAS 159. SFAS 159 provides companies with an option to report selected financial assets and liabilities at fair value. SFAS 159 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating the impact of implementation of SFAS No. 159 on our consolidated financial statements.

Note 7: Discontinued operations

In December, 2003, the Company decided to wind down its OSS business. This decision was made because of continuing losses combined with difficulties in marketing OSS products in view of the Company's financial condition. As of June 30, 2007, the Company discontinued operating this business. Accordingly, as of June 30, 2007, the OSS net assets of $434,000 were written off and the operations of the segment are reported in the Consolidated Financial Statements as a discontinued operation.

Results of operations for OSS have been segregated from continuing operations and are reflected as discontinued operations approximately as follows:

	Nine Months Ended September 30,	
	2007	2006
Revenues	$ 100,000	$ 276,000
Loss from discontinued operations	(87,000)	(245,000)
Write off of net assets of discontinued operations	(434,000)	—
Loss from discontinued operations	$ (521,000)	$ (245,000)

	Three Months Ended September 30,	
	2007	2006
Revenues	$ —	$ 80,000
Loss from discontinued operations	—	(87,000)
Write off of net assets of discontinued operations	—	—
Loss from discontinued operations	$ —	$ (87,000)

Note 8: Subsequent events

On October 23, 2007 the Company borrowed $1,000,000 ("the New Note") from Cheyne , our senior debt holder. Interest accrues at an amount equal to the six month Libor rate plus 10%. Principal and accrued interest is payable December 1, 2007 and January 1, 2008, based on average excess cash availability over $250,000. The principal balance of the note and accrued interest is due on February 1, 2008**.** The new note is collateralized by all of the assets which are secured to the existing senior debt holder.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The Company's consolidated statements of operations for the periods indicated below, shown as a percentage of sales, are as follows:

	Nine Months Ended September 30,		Three Months Ended September 30,	
	2007	2006	2007	2006
Sales	100%	100%	100%	100%
Cost of sales	69%	66%	69%	67%
Gross profit	31%	34%	31%	33%
Selling, general and administrative expenses	21%	17%	23%	16%
Research and development expenses	5%	5%	6%	4%
Operating income	5%	12%	2%	13%
Interest expense - net	(7)%	(3)%	(8)%	(3)%
Income (loss) from continuing operations	(2)%	9%	(6)%	10%
Loss from discontinued operations	(3)%	(1)%	(0)%	(1)%
Net (loss) income	(5)%	8%	(6)%	9%

The Company's sales, from continuing operations, by product line for the periods ended September 30, 2007 and 2006 are as follows:

	Nine Months Ended September 30, $(000)					
	2007			2006		
Line	$	18,228	83%	$	21,308	85%
Signal		3,694	17%		3,731	15%
		21,922	100%	$	25,039	100%

	Three Months Ended September 30, $(000)					
	2007			2006		
Line	$	5,594	84%	$	7,694	85%
Signal		1,057	16%		1,324	15%
	$	6,651	100%	$	9,018	100%

Overview

We operate in the telecommunications industry, and our customer base consists largely of government-owned and privately-owned telecommunications companies. Our line connection and protection equipment ("Line") interconnects copper telephone lines to switching equipment and provides fuse elements that protect telephone equipment and personnel from electrical surges. Our signal processing ("Signal") equipment is used in data communication devices that employ high frequency transformer technology.

Our Line equipment is designed to connect copper-wired telecommunications networks and to protect telecommunications equipment from voltage surges. We market this equipment primarily to telephone operating companies outside the United States and through distribution to designers, engineers and installers in the United States. Our Line division generated net income from operations for the three and nine months ended September 30, 2007 and the comparable periods of 2006. We market Signal equipment principally for use in defense and aerospace applications. The Signal division generated net income from operations for the three and nine months ended June 30, 2007 and 2006. We recognize revenue from Line and Signal products when the product is shipped.

On September 30, 2007, our liability to our senior debt holder was $23,373,000 plus accrued interest of $312,000. On February 7, 2007, Cheyne purchased our senior debt of $23,400,000 from SHF IX, LLC and subsequently extended the maturity of our senior debt to February 1, 2008. In October 2007, Cheyne lent us an additional $1,000,000 which is due on February 1, 2008. We cannot give any assurance that our senior debt holder will extend the maturity date beyond February 1, 2008. Any adverse event, including declines in business, could have an effect on the decision of our senior debt holder to extend or demand payment on the notes. If our senior debt holder does not extend the maturity of our senior debt beyond February 1, 2008 or if our senior debt holder demands payment of all or a significant portion of the senior debt when due, we will not be able to continue in business, and it is likely that we will seek protection under the Bankruptcy Code.

We are very dependent upon a small number of customers, particularly British Telecommunications. Total sales to British Telecommunications, consisting of direct sales and sales to systems integrators for British Telecommunications (including Fujitsu) were $10,200,000 (47 % of sales) for the nine months ended September 30, 2007, $20,000,000 (62%) for the year end 2006, $13,900,000 (50%) for the year 2005 and $13,600,000 (50%) for the year 2004. To the extent that British Telecommunications reduces its purchases from, or purchases products at a price which results in a reduced gross margin, our ability to operate profitably will be impaired. During the nine months ended September 30, 2007, British Telecommunication changed its equipment purchase practices, with a result that our sales to British Telecommunications and its systems integrators declined from $15,500,000 for the nine months ended September 30, 2006 to $10,200,000 for the nine months ended September 30, 2007. This decline in sales is the principal reason for our loss from continuing operation of $531,000 as compared to income of $2,254,000 for the comparable period of 2006. We may not be able to replace this business from other customers and we cannot give any assurance that British Telecommunications will increase its purchases from us in the future.

We are engaged in discussions with Cheyne and the holders of our subordinated debt and other creditors regarding the restructuring of our debt. Any such restructuring, if approved by our lenders and our stockholders, would result in both a reduction of senior,subordinated debt and other debt and a significant increase in the number of our outstanding shares of common stock. If we are unable to increase our sales to a level where we can operate profitably or if we are unable to obtain stockholder approval, we may not be able to effect a debt restructuring, in which event it is likely that we will seek protection under the Bankruptcy Code.

Results of Continuing Operations

The below narratives discuss the activities of our continuing operations.

Line equipment sales for the nine months ended September 30, 2007, compared to the nine months ended September 30, 2006, decreased by $3,080,000 (14%) from $21,308,000 to $18,228,000. Sales for the three months ended September 30, 2007 decreased by $2,100,000 (27%) from $7,694,000 in 2006 to $5,594,000 in 2007. The decrease in sales for the nine and the three months is the result of a significant decline in orders from British Telecommunications that was partially offset by higher demand for connection and protection product from North America customers. The increased demand of connection and protection product was $1,908,000 and $541,000 for the nine and three months ending September 30, 2007, respectively. A significant percentage of our revenues are derived from British Telecommunications and its installers. Any continuation of the significant reductions in the level of business from British Telecommunications and its installers could continue to have a material adverse effect upon both our revenue and net income. Thus far this year we have experienced a significant drop off of orders from British Telecommunications' installers, although direct sales to British Telecommunications remain significant.

Signal sales for the nine months ended September 30, 2007 were $3,694,000, compared to $3,731,000 in the same period of 2006, a decrease of $37,000 (1%). Sales for the three months ended September 30, 2007 compared to 2006, decreased by $267,000 (20%) from $1,324,000 to $1,057,000. The decline in Signal revenue for the third quarter of 2007 was $267,000 (20%) primarily due to the deferral of anticipated orders from the military sector resulting from Congress' failure to approve the U.S. military budget.

Gross margin for the nine months ended September 30, 2007 was 31% compared to 34% for the nine months ended September 30, 2006. Gross margin for the quarter ended September 30, 2007 was 31% compared to 33% for the quarter ended September 30, 2006. The decrease for the quarter and nine months is primarily related to a change in product mix sold to British Telecommunications from the higher gross profit DSL products to the lower margin local loop unbundling products and less absorption of manufacturing overhead due to the lower level of revenue. Our Signal segment gross margin slightly increased during the quarter and nine months due to sales mix.

Selling, general and administrative expenses increased by $436,000 (11%) from $4,090,000 to $4,526,000 for the nine months ended September 30, 2007 compared to 2006. For the quarter ended September 30, 2007 selling, general and administrative expenses increased by $147,000 (11%) from $1,386,000 in 2006 to $1,533,000 in 2007. The selling expense increase for the nine months ended September 30, 2007 relates primarily to increased commission expenses. Selling expenses decreased in the third quarter primarily due to less advertising expenses, somewhat offset by higher commission, when compared to the 2006 quarter. General and administrative costs increased, for the nine months and the quarter, primarily due to increased expenses related to our debt restructuring efforts.

For the nine months ended September 30, 2007 compared to 2006, research and development expenses increased by $37,000 (3%) to $1,201,000 from $1,164,000. For the quarter ended September 30, 2007 compared to 2006, research and development expenses increased by $15,000 (4%) to $423,000 from $408,000. The increase for the nine months and the quarter resulted primarily from increased spending by our line division to enhance our existing line products and develop new products.

As a result of the foregoing, for the nine months ended September 30, 2007, we had an operating income from continuing operations of $1,056,000 compared with $3,192,000 in the same period of 2006. We had an operating income from continuing operations of $132,000 for the quarter ended September 30, 2007 as compared with $1,188,000 in the same period of 2006.

Interest expense, net, for the nine months ended September 30, 2007 was $1,536,000, an increase of $688,000 from $848,000 for the nine months ended September 30, 2006. For the three months ended September 30, 2007 the interest expense was $547,000 compared to $261,000 for the comparable period last year. These increases of $688,000 and $286,000 for the nine months and three months, respectively, are primarily related to interest on our senior debt under the terms of our extension agreement with the senior debt holder. We do not accrue interest on the entire amount of the senior debt of $23,373,000 under the terms of our agreement with the holder of our senior debt. Interest has accrued from February 7, 2007 on $10,000,000 of the senior debt at 12.5% as a result of the terms of the February 7, 2007 extension of the maturity of our senior debt.

Income tax expense for the quarter and nine months ended September 30, 2007 relates to state and foreign taxes. No federal income tax expense has been provided due to losses incurred during the nine month period

As a result of the foregoing, we generated a net loss from continuing operations of ($531,000), or ($.05) per share (basic and diluted), for the nine months ended September 30, 2007, compared with net income from continuing operations of $2,254,000, or $.22 per share (basic and diluted) in 2006. The net loss for the three months ended September 30, 2007, from continuing operations, was ($425,000), or ($.04) per share (basic and diluted), compared with net income of from continuing operations $905,000, or $.09 per share (basic and diluted)in the comparable quarter of 2006.

Liquidity and Capital Resources

At September 30, 2007, we had cash and cash equivalents of $396,000 compared with $2,102,000 at December 31, 2006. The reduction in our cash position primarily reflects increases of $97,000 in accounts receivable and $1,385,000 in inventory, a decrease of $634,000 in accounts payable and payments of $633,000 with respect to our senior debt, of which $140,000 was principal and $493,000 was interest. These factors were also reflected in our working capital deficit at September 30, 2007 of $32,643,000, as compared with a working capital deficit of $31,646,000 at December 31, 2006, an increase of $997,000 in our working capital deficit.

During the first nine months of 2007, we paid $633,000 to our senior debt holder of which approximately $140,000 was applied to principal and $493,000 was applied to interest.

As of September 30, 2007, our senior debt includes $23,373,000 of principal and $312,000 of accrued interest, which matures on February 1, 2008; and $6,529,000 of principal and $6,844,000 of accrued interest on our subordinated notes and 6% debentures that became due on July 3, 2001 and July 2, 2002, respectively. We are prohibited by our senior debt holder from paying principal or interest on any of the subordinated debt. At September 30, 2007, we did not have sufficient resources to repay either the senior lender or the subordinated lenders and it is unlikely that we can generate such cash from our operations. Subsequent to the quarter ended September 30, 2007 the Company borrowed $1,000,000 from Cheyne Special Situation Fund, our senior debt holder in order to meet current working capital requirements. This loan, along with the existing senior debt, matures on February 1, 2008.

As of June 30, 2007, the Company discontinued operating the OSS division. Accordingly, as of June 30, 2007, the OSS net assets of $434,000 were written off and the operations of the OSS segment are reported in the Consolidated Financial Statements as a discontinued operation.

We are seeking to address our working capital and liquidity problems by seeking a restructuring of our senior and subordinated debts as well as significant amounts of unsecured debt due to third parties. Although the debt restructuring, if implemented, will improve our working capital, it will not provide us with any additional cash for our operations. Our only source of funds is Cheyne, which advanced us $1,000,000 in October 2007. However, our continuing losses and the uncertainty of any significant increase in business from British Telecommunications will increase the difficulties in obtaining financings from other sources, and we cannot give any assurance that Cheyne will provide us with any additional funding if the need arises. Any restructuring of our Company will result in very significant dilution to the holders of our common stock and will require the approval of the holders of our common stock and subordinated debt. If we do not restructure our debt and the senior lender does not extend the maturity of our senior debt beyond February 1, 2008, or if our senior debt holder demands payment of all or a significant portion of the senior debt when due, whether on February 1, 2008 or upon the expiration of a subsequent extension, we will not be able to continue in business, and it is likely that we will seek protection under the Bankruptcy Code.

We have in the past, and may in the future, consider the sale of one or more of our divisions. However, all of our past discussions terminated without any agreement and we cannot give any assurance that we would be able to effect any sale of our business or that such a sale would not be part of a bankruptcy reorganization.

Forward Looking Statements

Statements contained in this Form 10-Q include forward-looking statements that are subject to risks and uncertainties. In particular, statements in this Form 10-Q that state our intentions, beliefs, expectations, strategies, predictions or any other statements relating to our future activities or other future events or conditions are "forward-looking statements." Forward-looking statements are subject to risks, uncertainties and other factors, including, but not limited to, those identified under "Risk Factors," in our Form 10-K for the year ended December 31, 2006 and in the Form 10-Q and those described in "Management's Discussion and Analysis of Financial Conditions and Results of Operations" in our Form 10-K and this Form 10-Q, and those described in any other filings by us with the Securities and Exchange Commission, as well as general economic conditions and economic conditions affecting the telecommunications industry, any one or more of which could cause actual results to differ materially from those stated in such statements. Such statements could be affected by risks and uncertainties related to our financial conditions, our relationship with the holder of our senior and subordinated debt, including the willingness or unwillingness of the holder of the senior debt to extend the maturity date of the senior debt and the amount and timing of any payments which the holder of the senior debt may require, our ability to sell any or all of our divisions or effect a restructure of our business and our debt and equity structure on terms acceptable to the holder of the senior debt, our relationship with British Telecommunications including its continued requirements for our products, factors which affect the telecommunications industry, market and customer acceptance, our access to current technology, competition, domestic and foreign government regulations and requirements and pricing, as well as general industry and market conditions and growth rates, and general economic conditions. Any forward-looking statements speak only as of the date on which they are made, and we do not undertake any obligation to update any forward-looking statement to reflect events or circumstances after the date of this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosure About Market Risk.

We conduct certain operations outside the United States. A substantial portion of our revenue and expenses from our United Kingdom operations are denominated in Sterling. Any Sterling-denominated receipts are promptly converted into United States dollars. We do not engage in any hedging or other currency transactions.

Item 4. Controls and Procedures

Management's assessment identified the following weaknesses at December 31, 2006 in our internal control over financial reporting and, subsequent to December 31, 2006, we took the following steps to address those weaknesses. Accordingly, as of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of our disclosure controls and procedures. Based on his evaluation, the Chief Executive Officer and Chief Financial Officer has concluded that our disclosure controls and procedures are effective.

Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during the fiscal quarter covered by this quarterly report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

Item 1 A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part 1, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2006, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form

10-K and in this Form 10-Q are not the only risks facing our Company.

During the quarter and nine months ended September 30, 2007, we sustained declines in revenue from our largest customer, British Telecommunications, from the comparable three and nine month periods of 2006, and, based on a change in the product mix, our gross margin declined on our sales to British Telecommunications. Due to our reliance on significant business from British Telecommunications, our revenue and net income could be impaired by any material reduction of sales to British Telecommunications or any material reduction in the gross margin on sales to British Telecommunications

Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Item 3. Defaults Upon Senior Securities.

See Note 3 of Notes to Unaudited Consolidated Financial Statements and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for information concerning defaults on our subordinated debt.

Item 6. Exhibits

31.1 Certificate of Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 Certificate of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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.

	PORTA SYSTEMS CORP.	
Dated: November 13, 2007	By	/s/Edward B. Kornfeld Edward B. Kornfeld Chief Executive Officer and Chief Financial Officer

Page 15 of 15