CARBON ENERGY CORP
Form 10-K/A
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SECURITES AND EXCHANGE COMMISSION

Washington D.C. 20549

FORM 10-K/A

Amendment No. 2

Annual Report Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

For the Fiscal Year Ended December 31, 2002

Commission File Number 1-15639

CARBON ENERGY CORPORATION

(Exact name of Registrant as specified in its Charter)

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

Registrants telephone number, including area code: **(303) 863-1555**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of Exchange on which registered
Common Stock, (no par value)	American Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

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, and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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

The aggregate market value of the 1,107,714 shares of voting stock held by non-affiliates of the registrant, based upon the closing sale price of the common stock on June 30, 2002 of $9.69 per share as reported on the American Stock Exchange, was $10,733,749. Shares of common stock held by each officer and director and by each person who owns 5% or more of the outstanding common stock have been excluded in that such persons may be deemed affiliates. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

As of March 19, 2003, the registrant had 6,150,323 shares of common stock outstanding.

PART I

ITEM 1. BUSINESS

GENERAL

Carbon Energy Corporation (the Company or Carbon) was incorporated on September 14, 1999 under the Colorado Business Corporation Act. The Company's business is comprised of the assets and properties of Carbon Energy Corporation (USA) (Carbon USA), which conducts the Company's operations in the United States and the assets and properties of Carbon Energy Canada Corporation (Carbon Canada), which conducts the Company's operations in Canada. Effective July 11, 2002, Carbon changed the name of its United States subsidiary from Bonneville Fuels Corporation (Bonneville Fuels) to Carbon Energy Corporation (USA). Effective March 1, 2003, Carbon changed the name of its Canadian subsidiary from CEC Resources Ltd. (CEC Resources) to Carbon Energy Canada Corporation. As the parent company, Carbon provides management services to Carbon USA and Carbon Canada.

Carbon is an independent oil and gas company engaged in the exploration, development and production of natural gas and crude oil in the United States and Canada. The Company's areas of operations in the United States are the Piceance Basin in Colorado, the Uintah Basin in Utah, the Permian Basin in New Mexico and Texas, and Montana. The Company's areas of operations in Canada are central Alberta and southeast Saskatchewan.

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

At December 31, 2002, the Company had 67.4 billion cubic feet of natural gas equivalent ("Bcfe" where one barrel of oil is equivalent to six thousand cubic feet of gas) proved reserves compared to 59.0 Bcfe at December 31, 2001. Proved reserves at December 31, 2002 increased by 8.4 Bcfe or 14% compared to December 31, 2001. Net proved natural gas reserves totaled 62.5 Bcf of gas at December 31, 2002 compared to 53.9 Bcf at year end 2001, an increase of 8.6 Bcf or 16%. Crude oil and natural gas liquids at December 31, 2002 totaled 822,000 barrels compared to 851,000 barrels at year end 2001, a decrease of 29,000 barrels or 3%. Of these proved reserves, approximately 93% on a Mcfe basis are gas and approximately 74% are categorized as proved developed. At December 31, 2002, the pretax net present value of the reserves using year end prices and costs held constant and discounted at 10% was $106 million.

At December 31, 2002, Carbon USA's exploration and production operations were comprised of working interests in 246 producing oil and gas wells. Carbon USA operates 151 of these wells. At December 31, 2002, Carbon USA had an interest in over 179,000 net acres of oil and gas leases primarily located in the Piceance Basin of Colorado, the Uintah Basin of Utah, the Permian Basin of New Mexico and Texas, and Montana. During 2002, Carbon USA produced 3.0 Bcf of gas and 91,300 barrels of oil and natural gas liquids, amounting to 3.6 Bcfe or an average of 9.9 MMcfe per day. The addition during 2002 of 7.0 Bcfe to Carbon USA's net proved reserves resulted in a reserve replacement of 194% of the Company's 2002 production in the United States.

In September 2002, Carbon USA sold its interest in 20 producing natural gas and oil wells located primarily in Stanton and Morton counties, Kansas for $2.1 million in cash. On March 24, 2003, Carbon USA closed the sale of its interest in 97 gross (23.3 net) wells and 26,300 gross (8,000 net) acres located primarily in southeast New Mexico. The sale price was $15.7 million in cash, with an effective date of January 1, 2003. Daily average net production from the New Mexico properties was approximately 3,300 Mcf of gas per day and 130 barrels of oil per day. These asset sales completed Carbon's program to sell assets acquired in the 1999 purchase of Bonneville Fuels that did not fit with the Company's focus on the development of its natural gas properties in the Piceance and Uintah Basins and in central Alberta.

At December 31, 2002, the estimated proved reserves attributed to the properties divested in March 2003 were 172,000 barrels and 7.3 Bcf of gas. The pretax net present value of these reserves using year end 2002 prices (except to the extent provided by contractual arrangement in existence at year end) and costs held constant and discounted at 10% was $15.9 million.

At December 31, 2002, Carbon Canada's exploration and production operations were comprised of working interests in 94 producing oil and natural gas wells located in Alberta and Saskatchewan. Carbon Canada operates 51 of these wells. The Company had an interest in over 49,000 net acres of oil and gas leases. During 2002, Carbon Canada produced 2.2 Bcf of gas and 50,300 barrels of oil and natural gas liquids, amounting to 2.5 Bcfe or an average of 6.9 MMcfe per day. The addition of 9.2 Bcfe to Carbon's net proved reserves resulted in a reserve replacement of 368% of the Company's 2002 production in Canada.

For information regarding Carbon's geographic segments, see Note 7 to the Consolidated Financial Statements.

On August 11, 1999, Carbon Canada entered into a stock purchase agreement with Bonneville Pacific Corporation (BPC), parent company of Carbon USA, for the purchase of all outstanding shares of Carbon USA. Rights and obligations of Carbon Canada under the stock purchase agreement were assigned to Carbon. Yorktown Energy Partners III, LP (Yorktown) purchased 4,500,000 shares of Carbon for $24.8 million. The funds from this purchase were used to acquire, on October 29, 1999, the Carbon USA shares under the stock purchase agreement and to pay expenses incurred in connection with the purchase and related transactions. The total cash purchase price after adjustments for Carbon USA was $23.5 million.

On January 21, 2000, Carbon commenced an exchange offer for shares of Carbon Canada. Through the exchange offer, Carbon offered to exchange one share of Carbon stock for each share of Carbon Canada stock. On February 18, 2000, the Company completed its offer to exchange Carbon shares for shares of Carbon Canada. Of the 1.5 million outstanding shares of Carbon Canada, over 97% of the shares were exchanged. Carbon began trading its shares on the American Stock Exchange on February 24, 2000 under the trading symbol CRB. On February 28, 2000, at the request of Carbon Canada, the Securities and Exchange Commission (SEC) approved the delisting of Carbon Canada's common stock from the American Stock Exchange.

On November 22, 2000, at the direction of its Board of Directors, Carbon Canada initiated an offer to purchase shares (the Offer) of Carbon Canada stock that were not owned by Carbon. The Offer was completed on February 6, 2001. Carbon Canada conducted the Offer in order to avoid the administrative costs and time involved in corresponding with a small number of minority shareholders. The Board of Directors of Carbon Canada maintained a neutral position in regard to the Offer because of potential conflicts of interest. Of the approximate 39,000 shares of Carbon Canada that were not acquired by Carbon in the original exchange offer, approximately 34,000 shares of Carbon Canada stock were purchased by Carbon Canada pursuant to the Offer.

On October 30, 2002, at a special meeting of the holders of Carbon Canada common stock, a special resolution was passed to amend the articles of Carbon Canada to consolidate its issued and outstanding common shares on a one-for-2,500 basis. The Board of Directors of Carbon Canada recommended the consolidation in order to avoid the administrative costs and time involved in corresponding with a small number of minority shareholders. On November 15, 2002, Carbon Canada initiated the exchange of common shares for post-consolidation shares or a cash payment in lieu of fractional post-consolidation shares. The exchange was completed on January 13, 2003. After the completion of the exchange, Carbon owns 100% of the stock of Carbon Canada.

On March 31, 2003, Carbon announced that it had entered into an Agreement and Plan of Reorganization (the Merger Agreement) with Evergreen Resources (Evergreen). Under the Merger Agreement, Carbon will merge with a subsidiary of Evergreen, and Carbon shareholders will receive .275 shares of Evergreen common stock for each outstanding share of Carbon common stock (and cash in lieu of any fractional shares). As a result of the merger, Carbon will become a wholly owned subsidiary of Evergreen. The merger is intended to be a tax-free, stock-for-stock transaction.

The Board of Directors of Carbon and Evergreen each unanimously approved the Merger Agreement. At the time of execution of the agreement, each of Yorktown and Patrick R. McDonald, President and Chief Executive Officer of Carbon, who beneficially own approximately 73.2% and 6.0%, respectively, of Carbon's outstanding common stock, has executed an agreement with Evergreen obligating each of them to vote all shares over which it has voting control in favor of the merger.

RBC Capital Markets acted as the financial advisor to Carbon and rendered a fairness opinion to the Board of Directors of Carbon.

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

BUSINESS STRATEGY

The Company's objective is to build shareholder value through consistent growth in reserves and production and to increase net asset value, cash flow, and earnings per share. Our business strategy is to grow through the exploration and development of oil and gas properties, by the acquisition of complementary properties and through the optimization of gathering, compression and processing facilities. In addition we seek opportunities to acquire additional oil and gas mineral leases and create drilling opportunities based on internally generated geological and engineering concepts. Management believes that the Company's existing infrastructure and its acreage position in the Piceance Basin in Colorado and the Uintah Basin in Utah and the Carbon and Rowley areas of Alberta, Canada provide the Company with an excellent opportunity to achieve its objectives. The Company may also pursue property acquisition opportunities in its areas of operations. The Company's objective and business strategy is subject to the proposed merger described above.

EMPLOYEES AND OFFICES

As of December 31, 2002, the Company had 24 employees located in Denver, Colorado and 12 in Calgary, Alberta. None of these employees are represented by a labor union. The Company's executive offices are located at 1700 Broadway, Suite 1150, Denver, Colorado 80290, and its telephone number is (303) 863-1555.

ITEM 2. PROPERTIES

United States

Piceance and Uintah Basins At December 31, 2002, Carbon owned working interests in 148 gross (128.7 net) producing wells in the Piceance Basin of Colorado and Uintah Basin of Utah. Carbon operates 132 of these wells. For the year ended December 31, 2002, the Company participated in the drilling of three gross (2.7 net) wells, all of which were completed as natural gas wells. The Company has leasehold rights in approximately 147,000 gross (126,000 net) acres of which approximately 108,000 gross (93,000 net) acres are undeveloped. Approximately 77,000 gross (62,000 net) undeveloped acres are held by production. Subject to completion of the proposed merger described previously, Carbon USA's focus in the United States during 2003 is to continue the development of its natural gas properties in the Rocky Mountains, with emphasis on the Piceance and Uintah Basins.

Permian Basin At December 31, 2002, Carbon owned working interests in 97 gross (23.3 net) producing wells in the Permian Basin of New Mexico and Texas. Carbon operates 18 of these wells. For the year ended December 31, 2002, the Company participated in the drilling of six gross (.7 net) wells, of which one gross (.1 net) was completed as a natural gas well, four gross (.3 net) were completed as oil wells and one gross (.3 net) was abandoned as a dry hole. The Company has leasehold rights in approximately 25,000 gross (8,000 net) acres of which approximately 8,000 gross (4,000 net) acres are undeveloped. Approximately 8,000 gross (2,000 net) undeveloped acres are held by production. In March 2003, Carbon USA sold its working and related leasehold interests in these properties.

Montana At December 31, 2002, Carbon owned a working interest and operated one gross (1.0 net) producing well in Montana. For the year ended December 31, 2002, the Company participated in the drilling of two gross (2.0 net) wells both of which were abandoned as dry holes. The Company has leasehold rights in approximately 47,000 gross (44,000 net) acres, approximately all of which are undeveloped.

Canada

Alberta At December 31, 2002, Carbon owned working interests in 85 gross (58.4 net) producing wells primarily in the Carbon and Rowley areas of Alberta. Carbon operates 51 of these wells. For the year ended December 31, 2002, the Company participated in the drilling of 17 gross (10.5 net) wells, resulting in 16 gross (10.0 net) natural gas wells and one gross (.5 net) dry hole. The Company has leasehold rights in approximately 76,000 gross (49,000 net) acres of which approximately 27,000 gross (22,000 net) acres are undeveloped. Subject to completion of the proposed merger described previously, Carbon's focus in Canada during 2003 is to continue the development of its natural gas properties in central Alberta, with emphasis on the Carbon and Rowley areas.

Saskatchewan At December 31, 2002, Carbon owned non-operating working interests in nine gross (2.8 net) producing wells in southeast Saskatchewan. For the year ended December 31, 2002, the Company did not participate in any drilling activities in this area. The Company has leasehold rights in approximately 2,000 gross (500 net) acres of which approximately 160 gross (40 net) acres are undeveloped.

RESERVES

The table below sets forth the Company's estimated quantities of historical proved reserves after royalty burdens and the present values attributable to those reserves as of December 31, 2002, 2001 and 2000. The estimates for the Company's reserves in the United States were prepared by Ryder Scott Company, an independent reservoir engineering firm. The estimates for the Company's reserves in Canada were prepared by Sproule Associates Limited, independent geological and petroleum engineering consultants. Additional information regarding the Company's proved and proved developed oil and gas reserves and the standardized measure of discounted net cash flow and changes therein are described in Note 13 to the Consolidated Financial Statements.

	United States			Canada		
	2002	2001	2000	2002	2001	2000
	(dollars in thousands, except price data)					
Estimated proved reserves						
Natural gas (MMcf)	36,677	33,992	32,100	25,805	19,868	18,867

	United States			Canada		
Oil and liquids (MBbl)	265	412	507	557	439	461
Total MMcfe	38,267	36,464	35,142	29,147	22,502	21,633
Proved developed reserves (MMcfe)(1)	29,991	31,355	28,714	19,959	16,822	18,659
Natural gas price as of December 31 ($/Mcf)	$ 3.14	$ 2.25	$ 9.76	$ 3.84	$ 2.30	$ 9.00
Oil and liquids price as of December 31 ($/Bbl)	29.84	18.45	25.50	24.68	13.02	21.73
Present value of estimated future net revenues before future income taxes, discounted at 10%	$ 42,264	$ 31,107	$ 153,528	$ 63,912	$ 24,684	$ 111,461

(1) Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

The estimate of net proved reserves in the United States at December 31, 2000 included volumes attributed to the Company's working interest in 40 natural gas wells located in the San Juan Basin of New Mexico. These properties were sold in January 2001. The estimated proved reserves attributed to these properties were 38,000 barrels of oil and 5.6 Bcf of natural gas. The pretax net present value of these reserves using year end 2000 prices (except to the extent provided by contractual arrangements in existence at year end) and costs held constant and discounted at 10% was $24.0 million.

The estimate of proved reserves in the United States at December 31, 2002 included volumes attributed to the Company's working interest in 97 gross (23.3 net) wells located primarily in southeast New Mexico. These properties were sold in March 2003. The estimated proved reserves for these properties were 172,000 barrels of oil and 7.3 Bcf of gas. The pretax net present value of these reserves using year end 2002 prices (except to the extent provided by contractual arrangements in existence at year end) and costs held constant and discounted at 10% was $15.9 million.

Reserve estimates are based upon various assumptions, including assumptions required by the Securities and Exchange Commission relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are not precise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will most likely vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves disclosed by the Company. In addition, the Company may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond its control.

In accordance with applicable requirements of the SEC, estimates of the Company's future net revenues are determined using sale prices estimated to be in effect as of the date of the reserve estimates and are held constant throughout the life of the properties (except to the extent provided by contractual arrangements in existence at year end). Also in accordance with the applicable SEC guidelines, future production costs are held constant at the level observed at the date of the reserve estimates. Declines in the price of oil or gas decrease reserve values by lowering the future net revenues attributable to the reserves and may also reduce the quantities of reserves that are recoverable on an economic basis. Price increases may have the opposite effect. A significant decline in prices of natural gas or oil could have a material adverse effect on the Company's financial condition and results of operations. Prices received for future production and future production costs may vary, perhaps significantly, from the prices and costs assumed for purposes of the estimates.

In general, the volumes of production from Carbon's oil and gas properties decline as reserves of oil and gas are depleted. Except to the extent the Company acquires additional properties containing proved reserves or conducts successful exploration and development activities or both, the proved reserves of the Company will decline as reserves are produced. Reserves generated from future activities of the Company are highly dependent upon the level of success in acquiring or discovering additional reserves and the costs incurred in doing so.

Since January 1, 2002, the Company has filed the Department of Energy Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," as required by operators of oil and gas properties in the United States. There are differences between the reserves as reported on Form

EIA-23 and reserves as reported herein. Form EIA-23 requires that operators report on total proved reserves for operated wells only and that reported reserves be reported on a gross basis rather than on a net basis.

PRODUCTION

The following table sets forth information regarding net oil and natural gas production, average sales prices and other production information. Average sales prices for natural gas, oil and liquids are inclusive of hedging gains and losses for the years ended December 31, 2002, 2001 and 2000:

	United States			Canada(1)		
	2002	**2001**	**2000**	**2002**	**2001**	**2000**
Quantities produced and sold						
Natural gas (MMcf)	3,049	2,810	3,374	2,232	2,419	1,312
Oil and liquids (Bbl)	91,297	81,091	69,394	50,274	58,615	39,662
Total MMcfe	3,597	3,297	3,790	2,534	2,771	1,550
Average sales price						
Natural gas ($/Mcf)	$ 2.17	$ 2.94	$ 2.80	$ 2.95	$ 4.05	$ 3.41
Oil and liquids ($/Bbl)	21.92	25.49	23.03	19.62	21.76	22.65
Average production (lifting) costs ($/Mcfe)	$ 0.45	$ 0.50	$ 0.42	$ 0.67	$ 0.58	$ 0.51

(1) Canadian results for 2000 are the results of Carbon Canada subsequent to its acquisition by Carbon in February 2000.

PRODUCTIVE WELLS

The following table sets forth information regarding the number of productive wells in which the Company held a working interest at December 31, 2002:

	Productive Wells(1)			
	Gas Wells		Oil Wells	
	Gross(2)	**Net(3)**	**Gross**	**Net**
United States				
Permian Basin	61	13.6	36	9.7
Piceance/Uintah Basins	145	125.7	3	3.0
Montana			1	1.0
Total	206	139.3	40	13.7
Canada				
Alberta	85	58.4		
Saskatchewan			9	2.8
Total	85	58.4	9	2.8
United States and Canada	291	197.7	49	16.5

	Productive Wells(1)

(1) Each well completed to more than one producing zone is counted as a single well. The Company has royalty interests in certain wells that are not included in this table.

(2) A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned.

(3) A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells.

The number of productive wells in which the Company held a working interest at December 31, 2002 included 61 gross (13.6 net) gas wells and 36 gross (9.7 net) oil wells attributed to properties located primarily in southeast New Mexico. These properties were sold in March 2003.

DRILLING ACTIVITY

The Company engages in exploratory and developmental drilling on its own and in association with other oil and gas companies. The following table sets forth the wells drilled for the years ended December 31, 2002, 2001 and 2000:

	United States			Canada(1)		
	2002	2001	2000	2002	2001	2000
Gross wells(2)						
Development						
Natural gas	2	6		14	11	8
Oil	4	7	6			
Non-productive(3)				1		
Total	6	13	6	15	11	8
Exploratory						
Natural gas	2	16		2		
Oil		3	4			
Non-productive	3	3	5			
Total	5	22	9	2		
Net wells(4)						
Development						
Natural gas	1.8	4.7		9.0	10.5	4.9
Oil	0.3	2.5	0.4			
Non-productive				0.5		
Total	2.1	7.2	0.4	9.5	10.5	4.9
Exploratory						

	United States			Canada(1)		
Natural gas	1.0	10.1		1.0		
Oil	2.5	2.5				
Non-productive	2.3	2.5	3.8			
Total	3.3	15.1	6.3	1.0		

(1) The results for 2000 are the results of Carbon Canada subsequent to its acquisition by Carbon in February 2000.

(2) A gross well is a well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned.

(3) A non-productive hole is a well deemed to be incapable of producing either natural gas or oil in sufficient quantities to justify completion as a natural gas or oil well.

(4) A net well is deemed to exist when the sum of the fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells.

At December 31, 2002, the Company was participating in the drilling of one gross (.1 net) well in the United States and three gross (2.8 net) wells in Canada.

DEVELOPED AND UNDEVELOPED ACREAGE

The following table sets forth the leasehold acreage held by the Company at December 31, 2002:

	Developed Acreage(1)		Undeveloped Acreage(2)	
	Gross(3)	Net(4)	Gross	Net
United States				
Permian Basin	17,201	4,664	8,150	3,550
Piceance and Uintah Basins	38,208	32,735	108,424	92,786
Montana	40	40	46,748	43,706
Wyoming	1,120	560	2,221	1,111
Total	56,569	37,999	165,543	141,153
Canada				
Alberta	48,480	27,448	27,360	21,564
Saskatchewan	1,520	432	160	40
Total	50,000	27,880	27,520	21,604

(1)

Developed acres are those acres which are spaced or assigned to productive wells.

(2) Undeveloped acres are considered to be those acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. It should not be confused with undrilled acreage held by production under the terms of a lease.

(3) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(4) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres.

The developed and undeveloped acreage position in the United States at December 31, 2002 included 17,201 gross (4,664 net) developed acres, and 8,150 gross (3,550 net) undeveloped acres attributed to lands located primarily in southeast New Mexico. These properties were sold in March 2003.

MARKETING

The Company sells natural gas, oil and natural gas liquids production from wells that it operates directly to purchasers including end users, marketers and refiners. Where the Company is not the operator of the well, it may directly market the production or it may contract to sell its share of production through the operator of the well.

The Company generally enters into short-term natural gas sales contracts and is typically paid a price based on the regional price set by the market place for natural gas deliveries to the regional interstate mainline transportation pipeline, a price which is generally less than the price set for natural gas deliveries to Henry Hub, the principal point for natural gas production in the Gulf Coast region of the United States and the point at which the price of the natural gas contract of the New York Mercantile Exchange (NYMEX) is set. The Company is typically paid on an index basis, net of mainline transportation charges incurred by the buyer. As of December 31, 2002, Carbon Canada is a party to various natural gas transportation contracts in Canada. Carbon Canada typically assigns these transportation contracts to the buyer of the Company's natural gas production for the term of the particular contract. The rights and obligations under these transportation agreements revert to the Company upon expiration of the natural gas sales contracts.

In the United States, oil is sold under contracts extending up to a year based upon monthly refiner price postings, which generally approximate the price of West Texas Intermediate crude oil adjusted to reflect transportation costs and quality. In Canada, oil and natural gas liquids are sold under short-term contracts at refiner posted prices for Alberta and Saskatchewan, adjusted to reflect transportation costs and quality.

For information regarding major purchasers of the Company's oil and natural gas, see Note 8 to the Consolidated Financial Statements.

COMPETITION

The oil and natural gas industry is highly competitive. The Company encounters competition from other oil and natural gas companies including major oil companies, other independent oil and natural gas concerns and individual producers and operators for the acquisition of producing properties and exploration and development prospects. The Company also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. The Company competes with a large number of companies having substantially larger technical staffs and greater financial and operational resources. The ability of the Company to increase reserves in the future will be dependent on its ability to generate successful prospects on its existing lands, to acquire producing properties and to acquire additional leases and prospects for future development and exploration.

TITLE TO PROPERTIES

Title to the Company's properties is subject to royalty, overriding royalty, carried, net profits, working and similar interests customary in the oil and gas industry. The Company's properties may also be subject to liens incident to operating agreements, as well as other customary encumbrances, easements and restrictions and for current taxes not yet due. For acquisitions of properties, the Company will conduct a title examination on all material properties. Prior to the commencement of drilling operations, a title examination and, if necessary, curative work will be performed. The methods of title examination adopted by the Company are reasonable in the opinion of management and are designed to insure that production from its properties, if obtained, will be salable for the account of the Company.

GOVERNMENT REGULATION

United States

The Company's United States operations are regulated at the federal, state and local levels. Natural gas and oil exploration, development, production and marketing activities are subject to various laws and regulations which may be periodically changed for a variety of political, economical and other reasons.

In the past, the federal government has regulated the prices at which oil and natural gas could be sold. The Natural Gas Wellhead Decontrol Act of 1989 removed all price controls affecting producing wellhead sales effective January 1, 1993. While sales by producers of oil, natural gas, and natural gas liquids can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. The Company's natural gas sales are affected by regulation of intrastate and interstate transportation. In recent years the Federal Energy Regulatory Commission (FERC) has issued a series of orders that has increased competition by, among other things, removing the transportation barriers to market access. These orders have had a significant impact upon gas markets in the United States and have fostered the development of a large spot market for gas and increased competition for gas markets. As a result of the FERC orders, producers can access gas markets directly but face increased competition for these markets. The Company believes that these changes have generally improved the Company's access to transportation and has enhanced the marketability of its natural gas production. To date the Company believes it has not experienced any material adverse effects as a result of these FERC orders; however the Company cannot predict what new regulations may be adopted by FERC and other regulatory authorities and the effect, if any, subsequent regulations may have on the Company.

The Company's oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the Federal government for operations on federal oil and gas leases. All of the jurisdictions in which the Company owns or operates producing oil and natural gas properties have statutory provisions regulating the exploration for and production of crude oil and natural gas. These statutes include the regulation of the size of drilling and spacing units and the number of wells which may be drilled in an area and the unitization or pooling of oil and natural gas properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, typically prohibit the venting or flaring of natural gas, and impose certain requirements regarding the apportionment of production from fields and individual wells. The effect of these regulations may limit the amount of oil and natural gas the Company can produce from its wells and limit the number of wells or location at which the Company can drill. State commissions establish rules for reclamation of sites, plugging bonds, reporting and other matters.

Increasingly, a number of city and county governments have enacted oil and natural gas regulations which have increased the involvement of local governments in the permitting of oil and natural gas operations and impart additional restrictions or conditions on the conduct of operators to mitigate the impact of operations on the local community. These local restrictions have the potential to delay and increase the cost of oil and natural gas operations.

Canada

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. Federal authorities do not regulate the price of oil and gas in export trade but instead rely on market forces to establish these prices. Legislation exists that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada. The Company does not expect that any of these controls and regulations will affect the Company in a manner significantly different than other oil and natural gas companies of similar size.

The provinces in which the Company operates have legislation and regulation which govern land tenure, royalties, production rates and environmental protection. The royalty regime in the provinces in which the Company operates is a significant factor in the profitability of the Company's production. Crown royalties are determined by government regulation and are typically calculated as a percentage of the value of production. The value of the production and the rate of royalties payable depends on prescribed reference prices, well productivity, geographical location and the type or quality of the product produced.

In Alberta, the Company is entitled to a credit against Crown royalties on most of the properties in which the Company has an interest in by virtue of the Alberta Royalty Tax Credit (ARTC). The credit is determined by applying a rate to a maximum of CDN $2.0 million of Crown royalties payable in Alberta for each company or associated group of companies. The rate is a function of the royalty tax credit par prices which is determined quarterly by the Alberta Department of Energy. The rate ranges from 25% to 75% depending upon petroleum prices for the previous quarter.

ENVIRONMENTAL REGULATION

United States

The Company, as a lessee and operator of natural gas and oil properties, is subject to various federal, state and local laws and regulations in the United States that provide for restriction and prohibition on releases or emissions of various substances produced in association with certain oil and gas industry operations which can affect the location of wells and facilities and can determine the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites and access be abandoned and reclaimed to the satisfaction of federal or state authorities, as applicable. These laws and regulations may, among other things, impose liability and penalties on the lessee for the cost of pollution cleanup resulting from operations, subject the lessee to liability for pollution damages, require suspension or cessation of operations in affected areas, and impose restrictions on the injection of liquids into subsurface aquifers that may contaminate ground water.

The Company has made, and will continue to make, expenditures in its efforts to comply with environmental regulations. The Company believes it is in compliance with applicable environmental laws and regulations in effect and that continued compliance with existing requirements will not have a material adverse impact on the Company. The Company has not been notified of, nor has any knowledge of any existing or pending environmental claims. Changes in existing environmental laws or the adoption of new environmental laws could have the potential to adversely affect the Company's operations. In connection with the Company's acquisition of Carbon USA, environmental assessments of Carbon USA's oil and gas properties were performed. No material noncompliance or clean-up liabilities requiring action were discovered. However, environmental assessments were performed on only a percentage of the Company's properties according to the value of the properties established at the time of acquisition.

The Company believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. No assurance can be given as to future capital expenditures which may be required for compliance with prospective environmental regulations.

Canada

In Canada, the oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions on releases or emissions of various substances produced or utilized in association with certain oil and gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such regulations may result in the imposition of fines and penalties, the suspension of operations and potential civil liability. The Environmental Protection and Enhancement Act imposes environmental standards and requires compliance with various legislative criteria including reporting and monitoring in Alberta. The Alberta Energy and Utility Board, pursuant to its governing legislation, also plays a role with respect to the regulation of environmental impacts of oil and gas activities.

OPERATING HAZARDS

The oil and gas industry involves a variety of operating risks including the risk of fire, explosion, blow-outs, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as oil spills, gas leaks, ruptures and discharge of toxic substances. The occurrence of any of these events might result in substantial losses to the Company due to injury and loss of life, severe damage to and destruction of property and natural resources and investigation and penalties and suspension of operations. The Company maintains insurance against some, but not all, potential risks. There can be no assurance that any such insurance that is obtained will be adequate to cover all losses or exposure for liability. Furthermore, the Company cannot predict whether such insurance will continue to be available at premium levels that justify its purchase.

ITEM 3. LEGAL PROCEEDINGS

Neither the Company nor its subsidiaries are engaged in any material legal proceedings.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

ITEM 5. MARKET FOR REGISTRANTS COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

On February 24, 2000, Carbon Energy shares began trading on the American Stock Exchange under the trading symbol CRB. The Company's equity securities consist of common stock with no par value. The range of the high and low closing prices of the Company's common stock for each quarterly period during 2002 and 2001 is as follows:

Quarter Ended	High	Low
March 31, 2002	$ 8.69	$ 7.90
June 30, 2002	9.90	8.60
September 30, 2002	9.89	9.50
December 31, 2002	10.25	9.70
March 31, 2001	$ 8.80	$ 6.81
June 30, 2001	12.31	8.80
September 30, 2001	9.90	8.20
December 31, 2001	9.59	8.60

On March 19, 2003, the closing price of the common stock was $10.50. There were approximately 40 holders of record of the common stock and 6.1 million shares outstanding.

The Company has not paid dividends on its common stock since inception and does not anticipate doing so in the future. Future payments of dividends, if any, will depend on the Company's earnings, capital requirements, loan restrictions, financial condition and other relevant factors. There is no assurance that the Company will ever pay dividends.

ITEM 6. SELECTED FINANCIAL DATA

The table below sets forth selected historical financial and operating data for Carbon and its predecessor, Bonneville Fuels, as of or for each of the years in the five-year period ended December 31, 2002. For 1999, the table presents the activities of the Company for November and December 1999 (the Company's operating activities prior to November 1, 1999 were minimal) and Carbon's predecessor, Bonneville Fuels, for the period January through October 1999, and a pro forma presentation for the combined operating and cash flow data for the year ended December 31, 1999. The twelve month figures as of or for the year ended December 31, 1998 are for Carbon's predecessor, Bonneville Fuels. Future results may differ substantially from historical results because of changes in oil and natural gas prices, production increases or declines and other factors. This information should be read in conjunction with the financial statements and notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations," presented elsewhere herein. Please see Note 7 and Note 14 to the Consolidated Financial Statements for information on geographic segments and quarterly data for 2002 and 2001.

	As of or for the Year Ended December 31,			Pro Forma for the Year Ended December 31, 1999	As of or for the Two Months Ended December 31, 1999	As of or for the Ten Months Ended October 31, 1999	As of or for the Year Ended December 31, 1998
	2002	2001	2000				
	(dollars in thousands, except per share data)						
Operating Data:							
Revenues	$ 18,071	$ 23,069	$ 17,649	$ 11,136	$ 1,915	$ 9,221	$ 7,912
Net earnings (loss)	(14,555)	1,573	1,456	147	(491)	638	(2,191)
Earnings (loss) per share:							
Basic	$ (2.39)	$ 0.26	$ 0.25	n/a	$ (0.12)	n/a	n/a
Diluted	(2.39)	0.25	0.25	n/a	(0.12)	n/a	n/a
Balance Sheet Data:							
Total assets	$ 52,304	$ 62,368	$ 62,480	n/a	$ 39,298	$ 22,912	$ 22,840
Working capital	(3,671)	(5,051)	(267)	n/a	232	1,954	562
Long-term debt	22,709	17,870	15,082	n/a	9,100	9,800	5,850
Stockholders' equity	18,608	33,854	32,235	n/a	24,315	9,701	9,063
Cash Flow Data:							
Cash provided by (used in) operating activities	$ 2,657	$ 14,232	$ 3,755	$ (713)	$ 999	$ (1,712)	$ 4,696

	As of or for the Year Ended December 31,						
Cash used in investing activities	(7,572)	(17,297)	(8,266)	(28,841)	(24,110)	(4,731)	(5,948)
Cash provided by financing activities	4,875	3,089	3,526	28,056	24,106	3,950	3,450
EBITDA(1)	(6,612)	10,734	8,763	3,423	239	3,184	(42)

(1) Net earnings (loss) to EBITDA reconciliation:

Net earnings (loss)	$ (14,555)	$ 1,573	$ 1,456	$ 147	$ (491)	$ 638	$ (2,191)
Interest	1,054	836	1,104	556	102	454	238
Income taxes	747	2,091	667				(175)
Depreciation, depletion & amortization	6,142	6,234	5,536	2,720	628	2,092	2,086
EBITDA	$ (6,612)	$ 10,734	$ 8,763	$ 3,423	$ 239	$ 3,184	$ (42)

EBITDA (as used herein) is defined as net income (loss) before interest expense, income taxes, and depletion, depreciation and amortization. While EBITDA should not be considered in isolation or as a substitute for net income (loss), operating income (loss), cash flow provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles or as an indicator of a company's financial performance, the Company believes that it provides additional information with respect to its ability to meet its future debt service, capital expenditures and working capital requirements. When evaluating EBITDA, readers should consider, among other factors, (i) increasing or decreasing trends in EBITDA, (ii) whether EBITDA has remained at positive levels historically and (iii) how EBITDA compares to levels of interest expense. While the Company believes that EBITDA may provide additional information with respect to its ability to meet its future debt service, capital expenditures and working capital requirements, certain functional or legal requirements of its business may require it to utilize its available funds for other purposes.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

RESULTS OF OPERATIONS COMPARISON OF 2002 RESULTS TO 2001

The following table and discussion present comparative revenue, sales volumes, average sales prices, expenses and the percentage change between periods for the years ended December 31, 2002 and 2001.

	United States For the Year Ended December 31,			Canada For the Year Ended December 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	$ 10,154	$ 11,455	-11%	$ 7,573	$ 11,080	-32%
Marketing and other, net	344	532	-35%		2	n/a
Total revenues	10,498	11,987	-12%	7,573	11,082	-32%
Daily sales volumes:						
Natural gas (MMcf)	8.4	7.7	9%	6.1	6.6	-8%
Oil and liquids (Bbl)	250	222	13%	138	161	-14%
Equivalents production (MMcfe 6:1)	9.9	9.0	10%	6.9	7.6	-9%

	United States For the Year Ended December 31,			Canada For the Year Ended December 31,		
Average price realized:						
Natural gas (Mcf)	$ 2.67	$ 3.34	-20%	$ 2.95	$ 4.05	-27%
Oil and liquids (Bbl)	21.92	25.49	-14%	19.62	21.76	-10%
Direct lifting costs	$ 1,623	$ 1,654	-2%	$ 1,703	$ 1,612	6%
Average direct lifting costs/Mcfe	0.45	0.50	-10%	0.67	0.58	16%
Other production costs	3,170	3,015	-5%	82	14	486%
General and administrative, net	2,868	2,767	4%	2,019	1,736	16%
Depreciation, depletion and amortization	3,626	3,536	3%	2,516	2,698	-7%
Full cost ceiling impairment	12,003		n/a	1,215		n/a
Interest and other expense, net	804	653	23%	250	210	19%
Income tax provision	746	135	453%	1	1,956	-100%

Revenues for oil and gas sales of Carbon USA for the year ended December 31, 2002 were $10.2 million, an 11% decrease from 2001. The decrease was due to a decline in oil and natural gas prices partially offset by increased oil, liquids and natural gas production.

Revenues for oil, liquids and gas sales of Carbon Canada for the year ended December 31, 2002 were $7.6 million, a 32% decrease from 2001. The decrease was due primarily to a decline in oil, liquids and natural gas prices and a decrease in oil, liquids and natural gas production largely due to the voluntary curtailment in the third quarter of 2002 of over 200 MMcf of the Company's natural gas and associated natural gas liquids production due to low natural gas prices.

Average production in the United States for the year ended December 31, 2002 was 250 barrels of oil per day and 8.4 million cubic feet (MMcf) of gas per day, an increase of 10% from 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 in the Piceance and Permian Basins, partially offset by natural production declines. Due to low natural gas prices in the Piceance and Uintah Basins, the Company delayed the completion and pipeline connection of several newly drilled wells until the latter part of 2002. For the year ended December 31, 2002, Carbon USA participated in the drilling of 11 gross (5.4 net) wells of which four gross (.3 net) were completed as oil wells, four gross (2.8 net) were completed as gas wells, and three gross (2.3 net) wells were abandoned as dry holes. For the year ended December 31, 2001, Carbon USA participated in the drilling of 35 gross (22.3 net) wells of which ten gross (5.0 net) were completed as oil wells, 22 gross (14.8 net) were completed as gas wells and three gross (2.5 net) wells were abandoned as dry holes.

Average production in Canada for the year ended December 31, 2002 was 138 barrels of oil and liquids per day and 6.1 MMcf of gas per day, a decrease of 9% from 2001 on an Mcfe basis. The decrease was due primarily to the voluntary curtailment of natural gas and liquids production during the third quarter of 2002 and natural production declines in all operating areas, partially offset by successful drilling activities in the Carbon and Rowley areas of central Alberta. In addition, due to low natural gas prices in central Alberta, the Company delayed the completion and pipeline connection of several newly drilled wells until the fourth quarter of 2002. For the year ended December 31, 2002, Carbon Canada participated in the drilling of 17 gross (10.5 net) wells of which 16 gross (10.0 net) were completed as gas wells and one gross (.5 net) well was abandoned as a dry hole. For the year ended December 31, 2001, Carbon Canada participated in the drilling of 11 gross (10.5 net) wells all of which were completed as gas wells.

Average oil and liquids prices realized by Carbon USA decreased 14% from $25.49 per barrel for the year ended December 31, 2001 to $21.92 for 2002. The average oil price includes hedge losses of $83,000 or $.90 per barrel for the year ended December 31, 2002 compared to hedge gains of $25,000 or $.30 per barrel for 2001. Average natural gas prices realized by Carbon USA decreased 20% from $3.34 per Mcf for the year ended December 31, 2001 to $2.67 per Mcf for 2002. The average natural gas price includes hedge gains of $400,000 or $.14 per Mcf for the year ended December 31, 2002 compared to hedge losses of $1.5 million or $.53 per Mcf for 2001.

Average oil and liquids prices realized by Carbon Canada decreased 10% from $21.76 per barrel for the year ended December 31, 2001 to $19.62 for 2002. The average oil and liquids price includes hedge losses of $8,000 or $.16 per barrel for the year ended December 31, 2002 compared to hedge gains of $33,000 or $.56 per barrel for 2001. Average natural gas prices realized by Carbon Canada decreased 27% from $4.05 per Mcf for the year ended December 31, 2001 to $2.95 for 2002. The average natural gas price includes hedge gains of $3,000 for the year ended December 31, 2002 compared to hedge losses of $571,000 or $.24 per Mcf for 2001.

Marketing and other revenues for Carbon USA decreased 35% from $532,000 for the year ended December 31, 2001 to $344,000 for 2002. Marketing revenue for the year ended December 31, 2001 included mark-to-market gains of $1.2 million related to a derivative contract that did not qualify for hedge accounting treatment under provisions of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities." In conjunction with the adoption of SFAS No. 133, on January 1, 2001, the Company recorded a derivative loss (net of tax) of $1.5 million as the cumulative effect of a change in accounting principle related to this derivative contract. During the third quarter of 2001, the Company recorded a $625,000 impairment for an outstanding account receivable from a purchaser of the

Company's gas production. In addition, during 2001, the Company entered into certain commodity derivative contracts with Enron North America Corporation (ENAC), a subsidiary of Enron Corporation (Enron). During the fourth quarter of 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 treatment under SFAS No. 133. Consequently, in 2001 the Company recorded a loss of $328,000 consisting of $82,000 related to oil and gas hedge contracts that had or would have settled in 2001 and $246,000 related to contracts that would have settled in 2002. The amount deferred in accumulated other comprehensive income at December 31, 2001 of $246,000 was reclassified to earnings during 2002 based on the originally scheduled settlement periods of the contracts.

Direct lifting costs incurred by Carbon USA were $1.6 million or $.45 per Mcfe for the year ended December 31, 2002 compared to $1.7 million or $.50 per Mcfe for 2001. The decrease in direct lifting costs was primarily due to a decrease in the number of well workovers and equipment repairs compared to the year ended December 31, 2001.

Other production costs incurred by Carbon USA consisting primarily of severance taxes, gathering and processing fees and production overhead were $3.2 million for the year ended December 31, 2002 compared to $3.0 million for 2001. The increase was primarily due to increased gathering and processing fees and higher severance taxes due to increased oil, liquids and gas production, partially offset by lower oil, liquids and gas prices and a credit for prior period ad valorem taxes.

Direct lifting costs incurred by Carbon Canada were $1.7 million or $.67 per Mcfe for the year ended December 31, 2002 compared to $1.6 million or $.58 per Mcfe for 2001. The higher per Mcfe expense for the year ended December 31, 2002 was primarily due to compression expenses associated with the production of natural gas in Alberta and the effect of fixed operating costs that were not reduced during the voluntary curtailment of production during the third quarter of 2002.

General and administrative expenses incurred by Carbon USA (net of overhead reimbursements on operated wells), increased 4% from $2.8 million for the year ended December 31, 2001 to $2.9 million for 2002. The increase was primarily due to one time legal expenses of $160,000 related to unsuccessful litigation in which the Company was a plaintiff that was concluded in 2002. For the years ending December 31, 2001 and 2002, Carbon USA capitalized $196,000 and $162,000, respectively, of G&A related to geological and geophysical activities.

General and administrative expenses incurred by Carbon Canada (net of overhead reimbursements on operated wells) increased 16% from $1.7 million for the year ended December 31, 2001 to $2.0 million for 2002. The increase was primarily due to salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures.

Interest and other expense incurred by Carbon USA increased 23% from $653,000 for the year ended December 31, 2001 to $804,000 for 2002. The increase was due primarily to increased average debt balances during the year ended December 31, 2002 relative to 2001, partially offset by lower borrowing rates.

Interest and other expense incurred by Carbon Canada increased 19% from $210,000 for the year ended December 31, 2001 to $250,000 for 2002. The increase was due primarily to increased average debt balances during the year ended December 31, 2002 relative to 2001, partially offset by lower borrowing 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 Carbon Canada, the volume of proved reserves the Company acquired in the acquisitions and a ceiling test impairment recorded by the Company in the second quarter of 2002.

DD&A expense incurred by Carbon USA was $3.6 million or $1.01 per Mcfe for the year ended December 31, 2002 compared to $3.5 million or $1.07 per Mcfe for 2001. The decreased rate is primarily due to the ceiling test impairment recorded by the Company in the second quarter of 2002, partially offset by an increase in the DD&A rate per Mcfe due to the capitalized cost per Mcfe of reserves added in 2001.

DD&A expense incurred by Carbon Canada was $2.5 million or $.99 per Mcfe compared to $2.7 million or $.97 per Mcfe for 2001. The increased rate for the year ended December 31, 2002 compared to 2001 is due to the capitalized cost per Mcfe of reserves added during 2001, partially offset by a ceiling test impairment recorded by the Company in the second quarter of 2002.

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

At June 30, 2002, the methodology required the Company to use natural gas prices of $1.10 per MMBtu for Colorado and Utah and $1.43 per MMBtu for central Alberta. These prices were $2.32 per MMBtu for Colorado and Utah and $1.99 per MMBtu for Alberta less than the price for natural gas delivered to Henry Hub, the principal reference price for natural gas in the United States. The differential was considerably greater than the 36 month average historical differential at June 30, 2002 of $.37 per MMBtu for Colorado and Utah and $.29 per MMBtu for Alberta. The Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $14.0 million and $2.4 million, respectively. When product prices were adjusted for oil and natural gas hedges in place at June 30, 2002, the Company's capitalized costs exceeded the ceiling limitation in the United States and Canada by $12.0 million and $1.2 million, respectively. At June 30, 2002, the Company recorded a $12.0 million and $1.2 million non-cash charge in the United States and Canada, respectively, to reflect these impairments. See Note 1 to the Consolidated Financial Statements for additional information.

During the fourth quarter of 2002, natural gas prices received by Carbon for production in Colorado and Utah, where approximately 60% of the Company's domestic production is located, averaged approximately $2.50 per MMBtu, nearly $1.50 per MMBtu less than the price posted for natural gas delivered to Henry Hub. For most of 2002, natural gas prices for production in these areas were low relative to the rest of the producing areas in the United States. Lack of regional seasonal demand and inadequate pipeline transportation capacity necessary to transport natural gas to consuming regions is the principal factor contributing to the large price differentials. The prospect of additional pipeline capacity out of the region is expected to help alleviate the high price differentials received by Carbon and other Rocky Mountain gas producers. Continued volatility is expected to affect the price received for natural gas produced by Carbon in the United States and Canada.

Income tax expense incurred by Carbon USA was $746,000 for the year ended December 31, 2002 compared to $135,000 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 $5.6 million for the year ended December 31, 2002.

Income tax expense incurred by Carbon Canada was $1,000 for the year ended December 31, 2002 compared to $2.0 million for 2001. The decrease in the effective tax rate for the year ended December 31, 2002 was due to permanent differences in the deductibility of Canadian royalties for oil, liquids, and natural gas versus a resource allowance, that was magnified due to the small ($212,000) loss before income taxes for the year ended December 31, 2002.

RESULTS OF OPERATIONS COMPARISON OF 2001 RESULTS TO 2000

The following table and the discussion that follows present comparative revenue, sales volumes, average sales prices, expenses and the percentage change between periods for the years ended December 31, 2001 and 2000. The Company's Canadian operations were established in February 2000 through an exchange offer of Carbon shares for shares of Carbon Canada. The results for the Company's Canadian operations for 2000 in the following table are pro forma to reflect the acquisition of Carbon Canada as if it had occurred on January 1, 2000. No other adjustments from reported net income were made in the preparation of this schedule.

	United States For the Year Ended December 31,			Canada For the Year Ended December 31,		
	2001	2000	Change	2001	2000	Change
	(Dollars in thousands, except prices and per Mcfe information)			(Dollars in thousands, except prices and per Mcfe information)		
Revenues:						
Oil and gas revenues	$ 11,455	$ 12,100	-5%	$ 11,080	$ 5,945	86%
Marketing and other, net	532	245	117%	2	(70)	n/a
Total revenues	11,987	12,345	-3%	11,082	5,875	89%
Daily sales volumes:						
Natural gas (MMcf)	7.7	9.2	-16%	6.6	4.0	65%
Oil and liquids (Bbl)	222	190	17%	161	122	32%

	United States For the Year Ended December 31,			Canada For the Year Ended December 31,		
Equivalents production (MMcfe 6:1)	9.0	10.3	-13%	7.6	4.7	62%
Average price realized:						
Natural gas (Mcf)	$ 3.34	$ 3.11	7%	$ 4.05	$ 3.34	21%
Oil and liquids (Bbl)	25.49	23.03	11%	21.76	23.33	-7%
Direct lifting costs	$ 1,654	$ 1,602	3%	$ 1,612	$ 873	85%
Average direct lifting costs/Mcfe	0.50	0.42	19%	0.58	0.50	16%
Other production costs	3,015	3,218	-6%	14		n/a
General and administrative, net	2,767	1,989	39%	1,736	1,373	26%
Depreciation, depletion and amortization	3,536	4,042	-13%	2,698	1,698	59%
Interest and other expense, net	653	917	-29%	210	234	-10%
Income tax provision	135	44	207%	1,956	681	187%

Revenues for oil and gas sales of Carbon USA for the year ended December 31, 2001 were $11.5 million, a 5% decrease from 2000. The decrease was due primarily to decreased gas sales and natural production declines in all operating areas partially offset by increased oil production and increased oil and gas prices.

Revenues for oil, liquids and gas sales of Carbon Canada for the year ended December 31, 2001 were $11.1 million, an increase of 86% from 2000. The increase was due primarily to increased oil, liquids and gas production and higher gas prices.

Carbon USA's average production for the year ended December 31, 2001 was 222 barrels of oil per day and 7.7 million cubic feet (MMcf) of gas per day, a decrease of 13% from 2000 on a Mcf equivalent (Mcfe) basis where one barrel of oil is equal to six Mcf of gas. In January 2001, the Company divested its entire working interests and related leasehold rights in the San Juan Basin. Exclusive of this disposition, the Company would have increased its production for the year ended December 31, 2001 compared to 2000 by 4% on an Mcfe basis. The increase in production was due to successful drilling activities conducted during 2001 in the Piceance and Permian Basins, offset by natural production declines in all operating areas. For the year ended December 31, 2001, Carbon USA participated in the drilling of 35 gross (22.3 net) wells of which ten gross (5.0 net) were completed as oil wells, 22 gross (14.8 net) were completed as gas wells and three gross (2.5 net) wells were abandoned as dry holes. For the year ended December 31, 2000, Carbon USA participated in the drilling of 15 gross (6.7 net) wells of which ten gross (2.9 net) were completed as oil wells and five gross (3.8 net) wells were abandoned as dry holes.

Carbon Canada's average production for the year ended December 31, 2001 was 161 barrels of oil and liquids per day and 6.6 MMcf of gas per day, an increase of 62% from 2000 on an Mcfe basis. The increase was due primarily to successful drilling and recompletion activities in the Carbon and Rowley areas of central Alberta. For the year ended December 31, 2001, Carbon Canada participated in the drilling of 11 gross (10.5 net) wells all of which were completed as gas wells. For the year ended December 31, 2000, Carbon Canada participated in the drilling of eight gross (4.9 net) wells all of which were completed as gas wells.

Average oil prices realized by Carbon USA increased 11% from $23.03 per barrel for the year ended December 31, 2000 to $25.49 for 2001. The average oil price includes hedge gains of $25,000 or $.30 per barrel for the year ended December 31, 2001 compared to hedge losses of $414,000 or $5.98 per barrel for 2000. Average natural gas prices realized by Carbon USA increased 7% from $3.11 per Mcf for the year ended December 31, 2000 to $3.34 per Mcf for 2001. The average natural gas price includes hedge losses of $1.5 million or $.53 per Mcf for the year ended December 31, 2001 compared to hedge losses of $2.6 million or $.78 per Mcf for 2000.

Average oil and liquids prices realized by Carbon Canada decreased 7% from $23.33 per barrel for the year ended December 31, 2000 to $21.76 for 2001. The average oil and liquids price includes hedge gains of $33,000 or $.56 per barrel for the year ended December 31, 2001 compared to hedge losses of $186,000 or $3.51 per barrel for 2000. Average natural gas prices realized by Carbon Canada increased 21% from $3.34 per Mcf for the year ended December 31, 2000 to $4.05 for 2001. The average natural gas price includes hedge losses of $571,000 or $.24 per Mcf for the year ended December 31, 2001 compared to hedge losses of $987,000 or $.59 per Mcf for 2000.

Marketing and other revenues for Carbon USA increased 117% from $245,000 for the year ended December 31, 2000 to $532,000 for 2001. Marketing revenue for the year ended December 31, 2001 included mark-to-market gains of $1.2 million related to a derivative contract that did not qualify for hedge accounting treatment under provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." In conjunction with the adoption of SFAS No. 133, on January 1, 2001, the Company recorded a derivative loss (net of tax) of $1.5 million as the cumulative effect of a change in accounting principle related to this derivative contract. During the third quarter of 2001, the Company recorded a $625,000 impairment for an outstanding account receivable from a purchaser of the Company's gas production. In addition, during 2001, the Company entered into certain commodity derivative contracts with Enron North America Corporation (ENAC), a subsidiary of Enron Corporation (Enron). During the fourth quarter of 2001, Enron and ENAC filed for Chapter 11 bankruptcy, and the Company determined that the ENAC contacts no longer qualified for cash flow hedge accounting treatment under SFAS No. 133. Consequently, the Company recorded a loss of $328,000 consisting of $82,000 related to oil and gas hedge contracts that had or would have settled in 2001 and $246,000 related to contracts that would have settled in 2002.

Direct lifting costs incurred by Carbon USA were $1.7 million or $.50 per Mcfe for the year ended December 31, 2001 compared to $1.6 million or $.42 per Mcfe for 2000. The per Mcfe increase was primarily due to well and equipment repairs in the Permian and Piceance Basins performed in 2001.

Other production costs incurred by Carbon USA consisting primarily of severance taxes, gathering and processing fees and production overhead were $3.0 million for the year ended December 31, 2001 compared to $3.2 million for 2000. The decrease was primarily due to lower severance taxes due to declines in gas production.

Direct lifting costs incurred by Carbon Canada were $1.6 million or $.58 per Mcfe for the year ended December 31, 2001 compared to $873,000 or $.50 per Mcfe for 2000. The increase was primarily due to increased compression costs in the Carbon area which contributed to a corresponding increase in gas production.

General and administrative expenses incurred by Carbon USA, net of overhead reimbursements, increased 39% from $2.0 million for the year ended December 31, 2000 to $2.8 million for 2001. The increase was primarily due to a reduction in overhead reimbursements as a result of the sale of the Company's San Juan Basin properties, salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures and legal expenses related to the case of Bonneville Fuels Corporation vs. Williams Production RMT Company.

General and administrative expenses incurred by Carbon Canada, net of overhead reimbursements, increased 26% from $1.4 million for the year ended December 31, 2000 to $1.7 million for 2001. The increase was primarily due to salary increases, personnel additions and increased consulting costs in conjunction with the Company's higher level of capital expenditures.

Interest and other expense incurred by Carbon USA decreased 29% from $917,000 for the year ended December 31, 2000 to $653,000 for 2001. The decrease was due primarily to a reduction in average debt balances throughout 2001 as a result of proceeds received from the divestiture of the Company's San Juan Basin properties, decreased margin deposits related to the Company's derivative positions and a decrease in interest rates, partially offset by increased funding requirements for capital expenditures.

Interest and other expense incurred by Carbon Canada decreased 10% from $234,000 for the year ended December 31, 2000 to $210,000 for 2001. The decrease was due primarily to a reduction in debt as a result of increased cash flow from operating activities and a decline in interest rates, partially offset by increased funding requirements for capital expenditures.

Depreciation, depletion and amortization (DD&A) of 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 current DD&A has been determined primarily by the purchase price incurred in its acquisition of Carbon USA and Carbon Canada, and the volume of proved reserves the Company acquired in the acquisitions. For information regarding full cost accounting and DD&A, see Note 1 to the Consolidated Financial Statements.

DD&A expense incurred by Carbon USA decreased 13% from $4.0 million for the year ended December 31, 2000 to $3.5 million for 2001. The decrease was due primarily to decreased production. DD&A was $1.07 per Mcfe for the years ended December 31, 2000 and 2001.

DD&A expense incurred by Carbon Canada increased 59% from $1.7 million for the year ended December 31, 2000 to $2.7 million for 2001. The increase resulted primarily from increased production. DD&A expense was $.98 per Mcfe for the year ended December 31, 2000 compared to $.97 per Mcfe for 2001.

Income tax expense incurred by Carbon USA was $135,000 for the year ended December 31, 2001, an effective rate of 37%. This compares to income tax expense of $44,000 or an effective rate of 8% for 2000. The effective rate in 2000 was the result of a reversal of an income tax valuation allowance of $192,000.

Income tax expense incurred by Carbon Canada was $2.0 million for the year ended December 31, 2001 compared to $681,000 for 2000. The effective rate was 40% for both years.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2002, the Company had $52.3 million of assets. Total capitalization was $41.3 million, consisting of 45% of stockholders' equity and 55% of debt.

For a discussion of the Company's credit facilities, see Note 3 to the Consolidated Financial Statements in this report.

Net cash provided by operations for the year ended December 31, 2002 was $2.7 million compared to $14.2 million in 2001. Net cash provided by operations prior to changes in working capital for the year ended December 31, 2002 was $5.5 million compared to $8.6 million in 2001. The decrease in operating cash flow in 2002 compared to 2001 was primarily due to declines in oil, liquids and natural gas prices in all areas and voluntary curtailments of production in the third quarter of 2002 because of low gas prices, partially offset by increased oil, liquids and gas production in the United States for 2002.

Net cash provided by operations for the year ended December 31, 2001 was $14.2 million compared to $3.8 million in 2000. Net cash provided by operations prior to changes in working capital for the year ended December 31, 2001 was $8.6 million compared to $7.5 million in 2000. The increase in operating cash flow in 2001 compared to 2000 was primarily due to increased oil, liquids and gas production in Canada, increased oil, liquids and natural gas prices in all areas and decreased working capital requirements, especially a decline in margin deposit requirements for the Company's derivative accounts.

For the year ended December 31, 2002, Carbon USA spent approximately $4.5 million primarily to fund development and exploration activities in Colorado, Montana, New Mexico and Utah. Carbon USA received $3.1 million in proceeds related to the disposition of certain overriding royalty interests in the Piceance and Permian Basin and the sale of working interests and related leasehold rights in New Mexico and Kansas. For the year ended December 31, 2002, Carbon Canada spent approximately $6.1 million 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 year ended December 31, 2001, Carbon USA spent approximately $16.6 million primarily to fund development and exploration activities in Colorado, Utah and New Mexico. Carbon USA also received $6.8 million in proceeds related to the disposition of the Company's entire working interest and related leasehold rights in the San Juan Basin. For the year ended December 31, 2001, Carbon Canada spent approximately $6.7 million primarily to fund development activities in the Carbon area of central Alberta.

For the year ended December 31, 2000, Carbon USA spent approximately $4.8 million primarily to fund development and exploration activities in New Mexico. For the year ended December 31, 2000, Carbon Canada spent approximately $3.1 million primarily to fund development activities in the Carbon area of central Alberta.

Carbon's primary cash requirements for 2003, subject to completion of the proposed merger described previously, will be to fund exploration and development expenditures, finance acquisitions, repay debt, and for general working capital needs. At December 31, 2002, the Company had no cash balances as all available cash flow generated from operations was used to pay down the Company's long-term debt. The Company has budgeted capital expenditures for 2003, exclusive of unplanned acquisitions or divestitures, of approximately $21 million. At December 31, 2002, the Company is in compliance with all of its debt covenants and has no reason to believe that either of its credit facilities will require principal payments during the next twelve months. Under the facilities, funds available at December 31, 2002 were approximately $3.3 million. In addition, the new U.S. facility secured on December 31, 2002 with the Bank of Oklahoma National Association (Bank of Oklahoma) will provide the Company with an additional borrowing capability of $1.9 million compared to its current facility, for a total borrowing capacity of $5.2 million.

On March 24, 2003, Carbon USA closed on the sale of its interests in 97 gross (23.3 net) wells and 25,400 gross (8,200 net) acres located primarily in southeastern New Mexico. The sale price was $15.7 million with an effective date of January 1, 2003. The Company will initially use the proceeds from the sale to pay down debt and anticipates utilizing the resulting borrowing capacity to accelerate its 2003 exploration and development drilling program in the Piceance and Uintah Basins. The Company anticipates that there will be some downward modification to its bank borrowing capacity as a result of the sale of properties in March 2003, nevertheless, Carbon believes that available borrowings under its credit agreements, projected operating cash flows and cash received from the March 2003 asset sale will be sufficient to cover its working capital, planned capital expenditures, and debt service requirements for the next 12 months.

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

The table below sets forth the Company's contractual obligations at December 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**

	Payments Due By Period		
Revolving credit facility	$	$ 22,709	$
Operating leases	435	303	
Transporation agreements	113	107	
	$ 548	$ 23,119	$

Contractual obligations for the Company's revolving credit facilities are presented prior to the March 24, 2003 sale of Carbon USA's interests in southeastern New Mexico for $15.7 million.

DISCLOSURES REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes "forward-looking statements". All statements other than statements of historical facts included in the Annual Report on Form 10-K are forward-looking statements. Such statements address activities, events or developments that the Company expects, believes, projects, intends or anticipates will or may occur, including such matters as future capital, development and exploration expenditures, reserve estimates (including estimates of future net revenues associated with such reserves and the present value of such future net revenues), future production of oil and natural gas, business strategies, expansion and growth of the Company's operations, cash flow and anticipated liquidity, prospect development and property acquisition, obtaining financial or industry partners for prospect or program development, or marketing of oil and natural gas. Although the Company believes that the expectations reflected in the forward-looking statements and the assumptions upon which such forward-looking statements are based are reasonable, it can give no assurance that such expectations and assumptions will prove to be correct. Factors that could cause actual results to differ materially ("Cautionary Statements") are described, in among other places in the Marketing, Competition, and Government Regulation sections in this 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 1 to the Consolidated Financial Statements.

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

Capitalized costs are accumulated for the United States and Canada as separate cost centers and are depleted using the units of production method based on proved reserves of oil and gas. For purposes of the depletion calculation, oil and gas reserves are converted to an equivalent unit of measure where six thousand cubic feet of gas is equal to one barrel of oil. 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, capitalized costs less related accumulated depletion and deferred income taxes may not exceed the sum of the present value of future net revenue from estimated production of proved oil and gas reserves using a 10% discount factor and unescalated oil and gas prices and costs as of the end of the period; plus the cost of properties not being amortized, if any; plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects.

A non-cash ceiling test impairment of the Company's full cost pool was recorded in the second quarter of 2002 because the capitalized cost of its oil and natural gas reserves in the United States and Canada exceeded the ceiling limitation established for those reserves. The SEC requires that public companies utilizing the full cost method of accounting for oil and gas properties perform a ceiling test at the end of each quarterly reporting period. Under the SEC guidelines, the natural gas and oil prices used to determine the future value of the Company's oil and gas reserves are based on posted prices on the last day of the reporting period (with consideration of price changes only to the extent provided by contractual arrangements).

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 adjustment would significantly alter the rate of depletion.

Derivative Instrument and Hedging Activities Pursuant to Company guidelines, the Company utilizes derivative instruments only as a hedging mechanism and does not enter into speculative transactions. The Company has a Risk Management Committee to administer and approve all hedging transactions. Gains or losses from 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 marketing and other revenue, net. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flows.

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

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

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

INTEREST RATE RISK

Because of its debt position, the Company is exposed to interest rate risk on the unhedged portion of its debt. 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 December 31, 2002, the Company had $16.4 million of floating rate debt through its facility with Wells Fargo and $6.3 million through its facility with CIBC. 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 9 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 January 1, 2003, from a one percent change in interest rates would be approximately $157,000 before taxes.

FOREIGN CURRENCY RISK

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

COMMODITY PRICE RISK

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

At December 31, 2002, approximately 60% of the Company's United States production is in Colorado and Utah. After March 2002, natural gas prices for production in these areas were unusually low relative to the rest of the producing areas in the United States. Lack of regional seasonal demand and inadequate pipeline transportation capacity necessary to transport natural gas to consuming regions are principal factors contributing to the large price differentials. The prospect of additional pipeline capacity out of the region is expected to help alleviate the high price differentials received by Carbon and other Rocky Mountain gas producers. However, continued volatility is expected to affect the price received for natural gas produced by Carbon in the United States and Canada.

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

The table below sets forth the Company's derivative financial instrument positions related to its natural gas and oil production at December 31, 2002:

Swaps:

Carbon USA Contracts				Carbon Canada Contracts			
Time Period	**Bbl/ MMBtu**	**Weighted Average Fixed Price Bbl/MMBtu**	**Derivative Asset/ (Liability)**	**Time Period**	**Bbl/ MMBtu**	**Weighted Average Fixed Price Bbl/MMBtu**	**Derivative Asset/(Liability)**
			(thousands)				**(thousands)**
Gas				**Gas**			
01/01/03-12/31/03	1,400,000	$ 3.07	$ (541)	01/01/03-12/31/03	216,000	$ 2.83	$ (242)
Oil				**Oil**			
01/01/03-12/31/03	46,000	$ 25.42	$ (76)	01/01/03-12/31/03	37,000	$ 25.47	$ (57)

The Company periodically enters into long-term physical contracts for a portion of its natural gas and oil production. The table below sets forth fixed price sales contracts at December 31, 2002:

Fixed price contracts:

Carbon USA Contracts			Carbon Canada Contracts		
Time Period	**MMBtu**	**Weighted Average Fixed Price MMBtu**	**Time Period**	**MMBtu**	**Weighted Average Fixed Price MMBtu**
Gas			**Gas**		
01/01/03-03/31/03	180,000	2.57	01/01/03-12/31/03	778,000	$ 3.16

ITEM 8. FINANCIAL STA