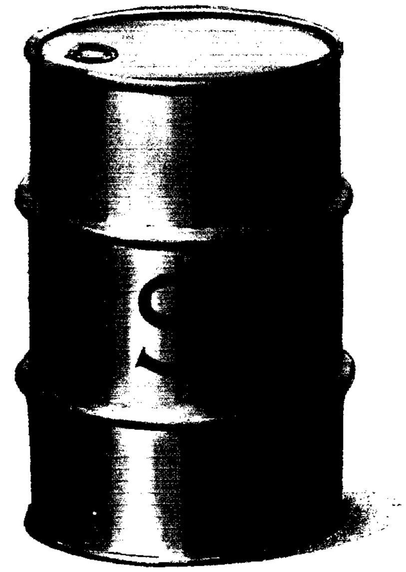
Harvest Natural Resources | *2002 Annual Report*

DEAR SHAREHOLDER:

Five milestones.

Since our last letter, we have continued on our journey towards that "promising new frontier" which we described for our shareholders last year – a frontier marked by value creation for our shareholders and prudent financial management. Our journey has at least five significant milestones, some of which we have already passed: 1. Restoring Investor Confidence, 2. Reinforcing our Foundation, 3. Overhauling our Operations, 4. Moving Forward with our Plan, 5. Harvesting Rewards for our Shareholders.

During 2002, we restored investor confidence by executing against our stated objectives of improving our financial flexibility and improving our operating fundamentals. As a result of our determined progress, investors rewarded the Company by boosting our stock price from $1.44 on January 1, 2002 to $6.45 at year end – making Harvest one of the best performers on the New York Stock Exchange. The trading price of our bonds also increased significantly reflecting not only lower absolute debt levels but also increased confidence in the Company's plans and the underlying value of our assets. We now stand on solid financial footing for the first time in many years.



MILE 1. STONE

Restoring Investor Confidence

Net income for 2002 was $100.4 million, or $2.78 per diluted share, compared with $43.2 million and $1.27 per diluted share in 2001. The increase in 2002 included an after tax gain on the sale of Arctic Gas of $93.6 million, offset in part by a pre-tax impairment of our license in offshore China of $13.4 million. Cash flow from operations for 2002 was $42.6 million compared with $36.6 million for 2001. These numbers show solid improvement over 2001 and fully met the guidance we offered at the start of the year.

At the same time, we focused our attention on improving our operating fundamentals, including improvement in our production practices and reserve optimization techniques, and aggressive cost cutting at both the corporate level and in the field. But that wasn't enough. We had to move forward and we did. We announced our new gas project in Venezuela, the first domestic gas project of its kind by a U.S. company, which not only increases our total recoverable reserves, but also will increase the cash flow from our Venezuelan assets. In Russia, we worked closely with our Russian partner in Geoilbent to begin the process of improving Geoilbent's potential.

The year was not always easy; and sometimes external factors slowed us down. The political unrest in Venezuela boiled over in late 2002. Our Venezuelan production was essentially shut-in in late December and only in February have we begun to see a return. Political uncertainty is still a point of concern in this important region.

Today, we continue to move forward with our plans with increased focus on the future. We are positioning the company for renewed and sustainable growth through a well-disciplined strategy of opportunity identification, exploitation, realization and harvest for our shareholders. We will be patient, prudent and good stewards of your investment, practicing solid governance and financial transparency in all that we do.

In the narrative that follows, we have attempted to chronicle our progress against the important milestones noted above in order to convey to you the same sense of confidence which your management team has in the future.

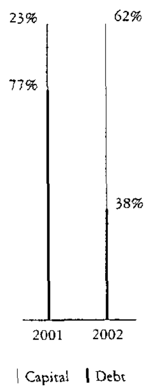
Milestone 1 - Restoring Investor Confidence

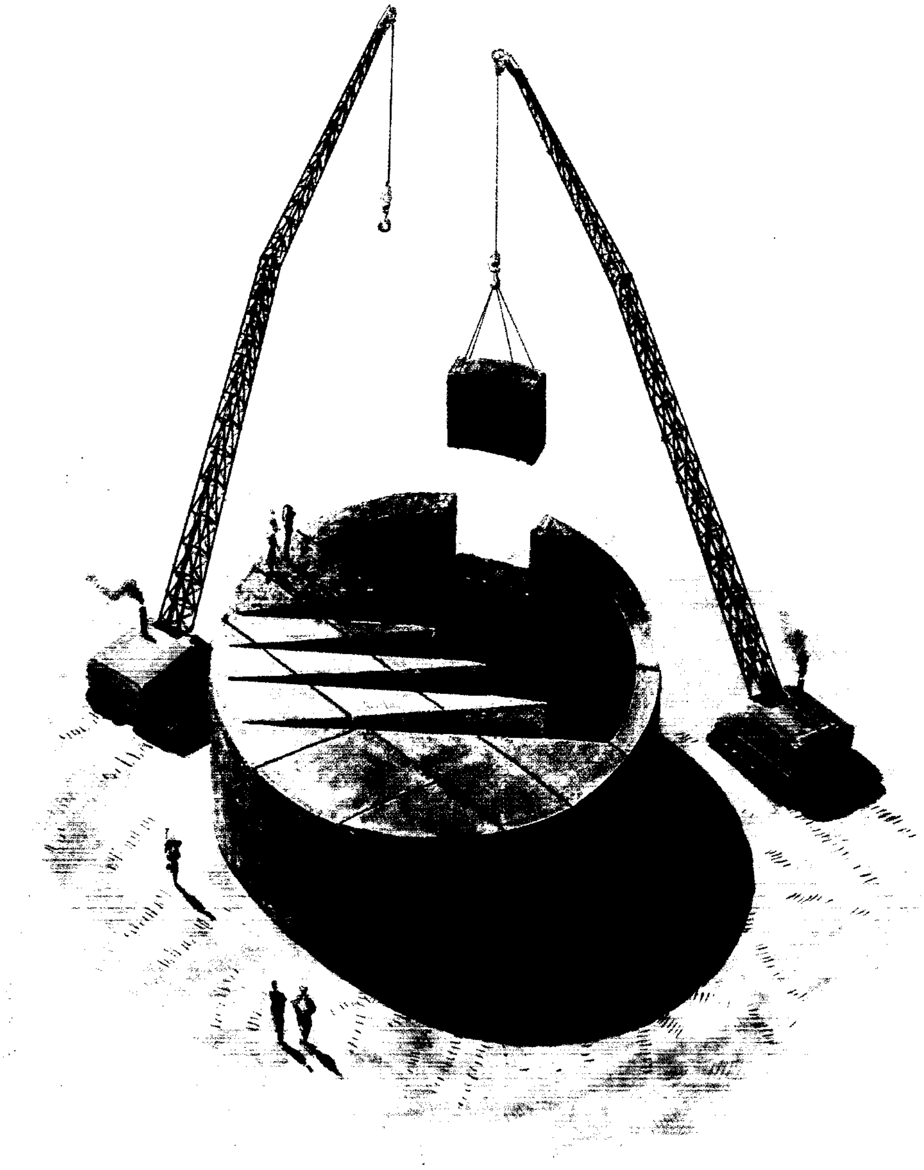
Last year, we said we had defined a new shared vision for Harvest and laid out two overriding strategic priorities: i) to reduce the amount of debt on the balance sheet; and, ii) to improve the value of our producing assets.

In 2002, we did what we said we would do – an important step to restoring lost investor confidence. Today, the balance sheet is strong. Completing the sale of Arctic Gas in April produced $220 million in cash. The net proceeds, after taxes and expenses, amounted to $190 million and were used, in part, to redeem all of the $108 million of 11-5/8% senior notes due in May 2003. An additional $20 million of the $105 million of 9-3/8% senior notes due in November 2007 were also retired. The balance of the proceeds we retained to improve our financial flexibility and to remain opportunistic with respect to external acquisitions. This strategy has already been partially rewarded by our ability to weather the storm caused by the continuing state of political unrest in Venezuela.

These actions restored our balance sheet to health and achieved the first of our strategic priorities. We have a debt to debt-plus-equity ratio of 38% and approximately $75 million of cash available as of February 28, 2003. This gives the Company enhanced financial flexibility in 2003.

Debt to Total Capital





MILESTONE 2.

Reinforcing Our Foundation

We also improved the value of our production, an equally important second priority. We have lowered operating expenses by 20% year-on-year to approximately $3.50 per barrel, increasing unit profitability. In Venezuela, we also successfully negotiated a contract to sell 198 billion cubic feet (bcf) of natural gas to the Venezuelan national oil company, Petroleos de Venezuela (PDVSA), over the next 10 years. Establishing a market for this gas allowed us to book an additional 26 million barrels of oil equivalent reserves to the Harvest proved reserve base.

We did not, however, meet our aggressive production target for 2002. While the interruption to our Venezuelan production in December was regrettable and beyond our control, our well planning and production delivery yielded disappointing results. This had a negative impact on our full year production. That we achieved all of our other 2002 financial targets was the result of higher world oil prices and the progress we have made in lowering our costs and improving our operating efficiency.

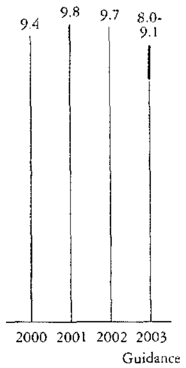
In 2002, Geoilbent, in which we have a 34% interest, increased production by 33% to 6.9 million barrels per year. Geoilbent has begun restructuring its balance sheet, by converting the loan with the European Bank for Reconstruction and Development (EBRD) into a $50 million revolving line of credit. Their new financing plans will allow Geoilbent to accelerate the development of the South Tarasovskoye oil field in western Siberia in 2003.

In retrospect, we believe it is fair to conclude that we have earned the confidence of our investors and are building a recognized track record which should translate into higher long-term value for our investors.

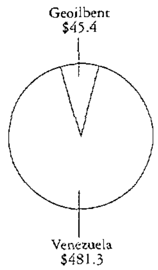
Milestone 2 - Reinforcing Our Foundation

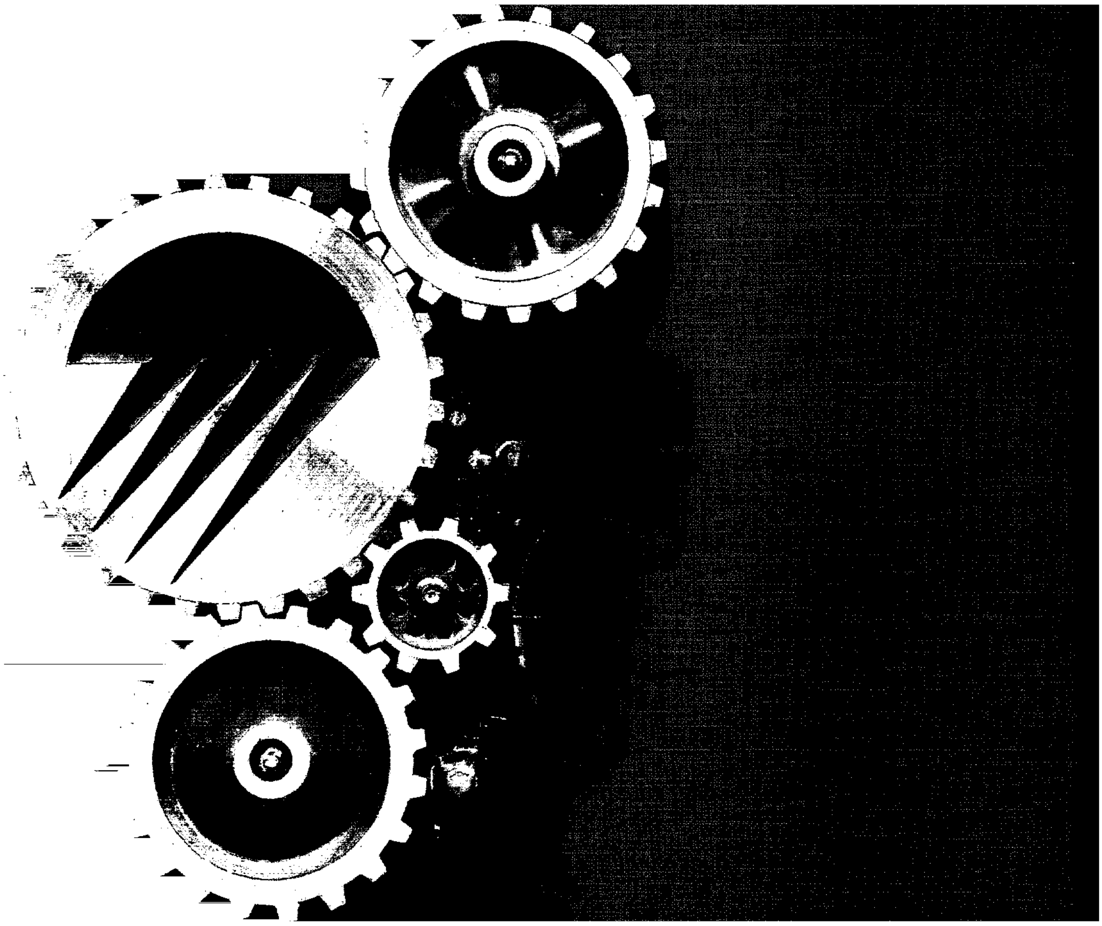
During 2002, we also strengthened our management team and recommitted, as a management team and board of directors, to maintain the highest standards in corporate governance, financial transparency and business ethics. During the year, we added Mr. Kerry Brittain as Vice President and General Counsel bringing invaluable experience in the areas of oil and gas exploration and production law, international business and corporate governance of public companies. While the board lost the valuable insights of Mr. Byron Dunn who did not stand for reelection to the board last year because of the pressure of other business priorities, the board embraced the broad move to improve corporate governance across the U.S. business spectrum as required by the Sarbanes-Oxley legislation and the New York Stock Exchange. We already had in place many of the new requirements since the board was reconstituted in 2000. We are actively monitoring the final rule making process and will continue to comply with both the letter and spirit of the law. Our company website, www.harvestnr.com, sets forth our corporate governance principles, mandates for the board and its committees and permits you to correspond directly with us.

Consolidated
Production
(millions of Bbl)



Pre-Tax
Present Value of Reserves
(millions of $)





3.

TONE

Overhauling Our Operations

Milestone 3 - Overhauling Our Operations

As of December 31, 2002, Harvest had total net estimated proved reserves of 101 million barrels of oil and 158 billion cubic feet of gas. This equates to 127 million barrels of oil equivalent, a 12% increase over 2001 year end totals, adjusted for the Arctic Gas sale. Venezuela oil reserves held steady at 76 million barrels and were supplemented by the addition of 26 million barrels of oil equivalent reserves from the commercialization of associated natural gas reserves. Geoilbent reserves declined by 17% to 25 million barrels of oil equivalent as a result of the lack of new development drilling on the North Gubkinskoye Field in western Siberia, and no further reserve appraisal of the South Tarasovskoye Field discovery.

V E N E Z U E L A

Quality Assets in Troubled Lands

Production in Venezuela approximated the 9.7 million barrels produced in 2002 in spite of the Venezuelan interruption in December. Excluding the effects of the production curtailment, we would have about met our target of 10.2 million barrels of production for 2002.

As we go to press with this letter, our Venezuelan production is slowly returning to pre-crisis levels. . Production was shut down between December 21, 2002 and February 8, 2003. In late February, we are producing about 23,000 barrels per day and hope to soon return to full production. However, it is impossible for us to predict what the ultimate impact of the continuing political and economic uncertainty in Venezuela will have on your company. We have worked diligently to protect our people, assets and franchise within Venezuela and will continue to manage cash to maximize our financial flexibility, satisfy all obligations and execute against our plans for growth.

During the past year, the Tucupita drilling campaign was successfully completed in the face of significant challenges, not the least of which was severe flooding then followed by delays to our water treatment and re-injection capacity. This experience reminds us again that our industry is one in which meticulous planning and flawless execution, as well as cooperation from mother nature, are all critical elements to success.

Prior to the shutting in of production in late December, we were achieving approximately 27,000 barrels of oil per day from the South Monagas Unit, with the Tucupita Field supplying some 10,000 bopd. This is the highest level of oil production ever reached in Tucupita since the field started production in 1945, and means the facilities are handling some 100,000 barrels of fluids per day. Together with an alliance partner, we employed "state-of-the-art" horizontal drilling techniques with open hole, gravel-packed completions to deliver high productivity wells. This has provided a "win-win" for both parties under a "performance incentive" program.

At the Uracoa Field, no new wells were drilled in 2002; but, through good well management, the natural decline of the field was stabilized. The field averaged around 17,000 bopd for the year. In late 2003, we anticipate returning to Uracoa to start a revised horizontal drilling program to accelerate recovery of untapped oil reserves which sit immediately beneath the gas cap.

MILESTONE 4.

Moving Forward With Our Plan

Lease Operating Expenses (LOE) dropped significantly in 2002, by 20%, to $3.50 per barrel and General and Administration Expense (G&A) fell to $1.70 per barrel. This is a result of our continued focus on costs and constantly looking at our operations to find savings and improve performance. While we will remain vigilant in maintaining an efficient cost structure, reductions in future unit costs will depend largely upon the success of our efforts to increase production.

RUSSIA

The World's New Frontier

In 2002, Harvest and our Russian partner contributed capital, people and technology to our joint investment in Geoilbent. Harvest supplied operational leadership designed to improve performance, financial results and accountability, and ultimately to enhance value creation. The 33% increase in oil production in Geoilbent was largely the result of increased production in the South Tarasovskoye Field. Discovered in July 2001, the first phase of field development centered on the northern crest of the structure which is shared with the adjacent licensee. Seventeen wells were drilled by Geoilbent, giving Geoilbent an average of 7,600 bopd (2.8 million barrels) for 2002; but, even more wells were drilled by our competitor. However, both parties now appreciate the need to cooperate in a shared pressure maintenance program in order to avoid too rapid of a depletion and poor ultimate recovery rates. A mutually beneficial field plan has been developed with the oversight of the Russian authorities and will be implemented in 2003. This plan will ultimately improve the effectiveness of Geoilbent's capital investments and improve ultimate recoveries without unduly damaging the reservoir.

In 2002, the North Gubkinskoye Field delivered 11,400 bopd (4.2 million barrels), down 18% year over year. This natural decline was in line with expectations. We are working on a revised field development plan needed to utilize the field's 100 wells more efficiently. A work-over program is planned for implementation during 2003. We also plan to have Geoilbent follow up on this phase of operations with a field management program which will permit the delivery of both gas and condensate production and optimize the oil production profile.

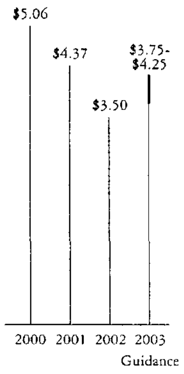
LOE at Geoilbent remained at around $2.00 per barrel, while G&A held at $1.30 per barrel. But, domestic pricing through the first six months of 2002 collapsed to between $4-6 a barrel, largely as a result of Russian support for OPEC calls for a reduction in world exports. This had a significant effect on profitability given that we can only export around 30% of our production into the higher value international market.

Milestone 4 - Moving Forward With Our Plan

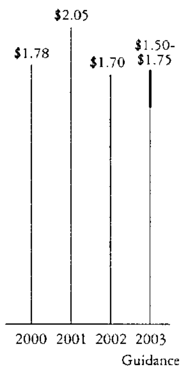
For 2003, our journey of purpose continues. We seek further improvements in the underlying fundamentals of our business and better financial performance. These goals are largely within our control; yet, our ultimate success will depend not only on a return to normalcy in Venezuela and a business environment where our people, assets and franchise are secure but also on our effort to diversify our sources of cash flow. Accordingly, we will have an eye on the future while we watch carefully the events in Venezuela. Prudence will be our watch word in preserving current values while pursuing the many exciting opportunities we see ahead. Our focus for the year will be on:

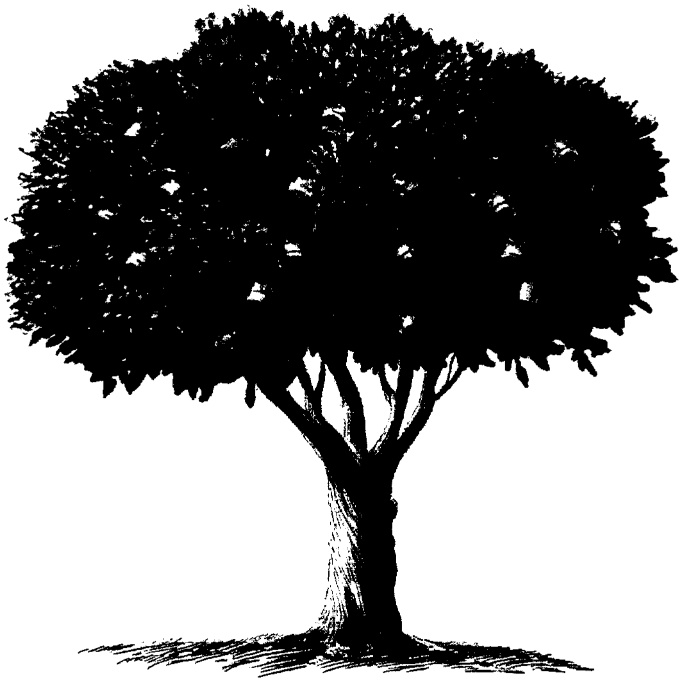
- *maintaining financial flexibility to manage against Venezuelan uncertainty*
- *continuing to improve the value of our produced barrel*
- *delivering the Venezuelan gas project in the 4th quarter of 2003 within budget*
- *maximizing the value of Geoilbent to Harvest*
- *remaining opportunistic in order to pursue acquisitions complementary to our strategies in Russia and Venezuela*

Consolidated
Lease Operating Expense
(per barrel)



Consolidated
General & Administrative
Expense
(per barrel)





MILES 5. TONE

Harvesting Rewards For Our Shareholders

These priorities are meant to be challenging. It is inescapable that the lion's share of the world's oil and gas supply lies outside the U.S. in countries which are still evolving as nations. We accept the challenge of helping to meet world demand and believe we can do so in a manner consistent with prudent risk taking and attractive returns and while contributing to the societies in which we do business. A goal of better diversifying our cash flow stream can perhaps best be accomplished by further direct investment in Russia. This is not to say that we will ignore growth opportunities in Venezuela which are very likely to surface when the current disruption is over. If conditions are right, Harvest is well positioned for further investment in Venezuela and we remain committed to the country and our employees.

We believe that Russia is full of opportunity and are confident we can continue to do good business there, well ahead of the international community. However, there is no set timetable to complete deals. We intend to be patient, seeking the right deal based on carefully identified investment criteria. The overall goal is to bring to Harvest currently producing, but largely undeveloped, resources of oil and gas. Through phased investment, we can then grow and capture the long-term value of the asset. We seek material, legacy assets, with controlling ownership interest in partnership with local industry partners with the necessary familiarity of the asset and area's working environment.

Milestone 5 - Harvesting Rewards For Our Shareholders

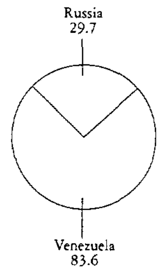
The year 2003 begins with many challenges. We are planning for generally lower financial and operating targets for the year reflecting both the unanticipated impact of the Venezuelan situation and the anticipated "plateau effect" as we transition from production, earnings and cash flow derived largely from investments made over nearly eleven years to reaping the benefit from the investment initiatives made in 2002 and 2003. Accordingly, 2003 represents an inflexion point in the Company's history which will mark the beginning of yet another new era for Harvest Natural Resources.

Since the new Harvest team came on board in 2000, we have committed to managing the Company for long term value creation while maximizing returns from the current asset base. This strategy has been rewarded by our investors thus far and we will continue to execute our plans with even higher expectations for the future. It means, however, that we are prepared to forego some short-term returns in exchange for higher returns later. Important elements in our transformation during 2003 will include:

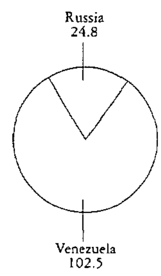
- *a shift in focus from drilling wells for the sole purpose of producing oil to drilling wells capable of producing oil and gas in both Russia and Venezuela as reserve profiles change*
- *new investments in gas infrastructure to address the needs of new markets*
- *converting a significant cash position and unused borrowing capacity to investment in higher returning assets to diversify cash flow and earnings streams*
- *implementation of focused field development plans to rejuvenate "tired" wells, some with production histories dating back 10 years or more*

Proved Reserves
(MMBOE)

2001



2002



Dr. Peter J. Hill

Stephen D. Chesebro'

Each of these elements represents opportunity for creating long-term, sustainable value with only a modest impact on near-term costs. But each also represents a critical ingredient which drives our exciting future.

In summary, for 2003 we have laid out some ambitious goals. It may seem like a year of consolidation and transition. But we can assure you, we aim to transform the Company from the much improved production platform we re-built over the last two years into a company of new growth. Plans are well designed and proceeding with dispatch. We are confident in our business model and believe we can deliver additional and exciting growth for the long-term benefit of our shareholders.

Only by repeatedly living up to our promises can we further build the trust and confidence of our shareholders. We have made a good start, but now we are intent on building an even more valuable asset base.

Once again, we thank the management and employee team for their efforts and sacrifices without which none of the success of 2002 would have happened. We expect nothing less for 2003 and the years ahead. Our thanks also go the Board for their continued help, commitment and thoughtful advice.

Together we progress towards a new era of sustainable growth, to new horizons and opportunities and to continued bountiful harvests for all stakeholders in your company.

Respectfully,

Stephen D. Chesebro'
Chairman

Dr. Peter J. Hill
President and Chief Executive Officer

Board of Directors

Stephen D. Chesebro'
Chairman of the Board
Retired President and CEO, Pennzenergy Company
Former Chairman and CEO, Tenneco Energy, Inc.

John U. Clarke
President
Concept Capital Group, Inc.

H.H. "Will" Hardee
Senior Vice President, Investment Officer
RBC Dain Rauscher, Inc.

Dr. Peter J. Hill
President and Chief Executive Officer
Harvest Natural Resources, Inc.

Patrick M. Murray
Chief Executive Officer
Dresser, Inc.

Officers

Dr. Peter J. Hill
President and Chief Executive Officer

Steven W. Tholen
Senior Vice President and Chief Financial Officer

Kerry R. Brittain
Vice President, General Counsel and Secretary

Kurt A. Nelson
Vice President and Controller

Financial Highlights

(in thousands, except per share)	2002	2001	2000
	Year Ended December 31,		
Financial:			
Total Revenues	$126,731	$122,386	$140,284
Net Income	100,362	43,237	20,488
Per Share (Diluted)	2.78	1.27	0.66
Total Assets	335,192	348,151	286,447
Long-Term Debt [1]	104,700	221,583	213,000
Stockholders' Equity	171,317	67,623	12,904
Average Shares Outstanding (Diluted)	36,130	34,008	30,890
Operational:			
Total Production [2]:			
Crude Oil and Condensate (MBbls)	10,205	9,982	8,991
Natural Gas (MMCF)	-	-	43
Oil Equivalents (MBOE)	10,205	9,982	8,998
Average Prices [3]:			
Crude Oil and Condensate (Per Bbl)	$13.08	$12.52	$14.94
Natural Gas (Per Mcf)	-	-	4.63
Total Proved Reserves [4]:			
Crude Oil and Condensate (MBbls)	100,916	134,243	146,866
Natural Gas (MMcf)	158,400	208,010	152,496
Oil Equivalents (MBOE)	127,315	168,911	172,282
Present Value of Reserves [2] [4]	$526,679	$365,735	$583,141

(1) Net of current portion

(2) Includes our proportionate share of production, reserves and present value of reserves from Benton-Vinccler, Geoilbent and prior to 2002 Arctic Gas

(3) On sales from consolidated companies

(4) Future net cash flows before income taxes discounted at 10%

Abbreviation Guide

Bbl	Barrel
MBbls	Thousand Barrels
Mcf	Thousand Cubic Feet
MMcf	Million Cubic Feet
MBOE	Thousand Barrels of Oil Equivalent

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2002,

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCAHNGE ACT OF 1934

Commission File No.: 1-10762

HARVEST NATURAL RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Delaware	77-0196707
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
15835 Park Ten Place Drive, Suite 115 Houston, Texas	77084
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (281) 579-6700

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

Title of each class	Name of each exchange on which registered
Common Stock, $.01 Par Value	NYSE

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

Title of each class	Name of each exchange on which registered
None	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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes __X__ No ____

Indicate 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. [ ]

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity as of the last business day of the registrant's most recently completed second fiscal quarter, June 28, 2002: $174,945,360.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practical date. Class: Common Stock, par value $0.01 per share, on March 21, 2003, shares outstanding: 35,216,211.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement for the 2003 Annual Meeting of Stockholders to be filed with the Securities and Exchange Commission, not later than 120 days after the close of its fiscal year, pursuant to Regulation 14A, are incorporated by reference into Items, 10, 11, 12, and 13 of Part III of this annual report.

HARVEST NATURAL RESOURCES, INC.

FORM 10-K

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PART I

Harvest Natural Resources, Inc. ("Harvest" or the "Company") cautions that any forward-looking statements (as such term is defined in the Private Securities Litigation Reform Act of 1995) contained in this report or made by management of the Company involve risks and uncertainties and are subject to change based on various important factors. When used in this report, the words "budget", "anticipate", "expect", "believes", "goals", "projects", "plans", "anticipates", "estimates", "should", "could", "assume" and similar expressions are intended to identify forward-looking statements. In accordance with the provisions of the Private Securities Litigation Reform Act of 1995, we caution you that important factors could cause actual results to differ materially from those in the forward-looking statements. Such factors include our substantial concentration of operations in Venezuela, the political and economic risks associated with international operations, the anticipated future development costs for our undeveloped proved reserves, the risk that actual results may vary considerably from reserve estimates, the dependence upon the abilities and continued participation of certain of our key employees, the risks normally incident to the operation and development of oil and gas properties and the drilling of oil and natural gas wells, the availability of materials and supplies necessary to projects and operations, the price for oil and natural gas and related financial derivatives, changes in interest rates, basis risk and counterparty credit risk in executing commodity price risk management activities, the Company's ability to acquire oil and gas properties that meet its objectives, changes in operating costs, overall economic conditions, political stability, civil unrest, acts of terrorism, currency and exchange risks, currency controls, changes in existing or potential tariffs, duties or quotas, availability of sufficient financing, changes in weather conditions, and ability to hire, retain and train management and personnel. See Risk Factors included in Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations.

At the end of Item 1 is a glossary of terms.

Item 1. Business

General

Harvest Natural Resources, Inc. is an independent energy company engaged in the development and production of oil and gas properties since 1989, when it was incorporated under Delaware law. We have developed significant interests in the Bolivarian Republic of Venezuela ("Venezuela") and the Russian Federation ("Russia") through our equity affiliate, and have undeveloped acreage offshore China. Our producing operations are conducted principally through our 80 percent-owned Venezuelan subsidiary, Benton-Vinccler, C.A. ("Benton-Vinccler"), which operates the South Monagas Unit in Venezuela; and Limited Liability Company Geoilbent ("Geoilbent"), a Russian company of which we own 34 percent and which operates the North Gubkinskoye and South Tarasovskoye Fields in West Siberia, Russia. On February 27, 2002, we entered into a Sale and Purchase Agreement to sell our entire 68 percent interest in Arctic Gas Company ("Arctic Gas"), to a nominee of the Yukos Oil Company, a Russian oil and gas company, for $190 million plus approximately $30 million as repayment of inter-company loans owed to us by Arctic Gas (the "Arctic Gas Sale"). On April 12, 2002, we completed the Arctic Gas Sale and recognized a gain of $144.0 million ($93.6 million after tax). From December 14, 2002 through February 6, 2003, no sales of our Venezuelan oil production were made because of Petroleos de Venezuela, S.A.'s ("PDVSA") inability to accept our oil due to the national civil work stoppage in Venezuela. In restoring production, we encountered problems with some of our wells, but we do not believe the associated costs will be material. By the end of March 2003, our average production was approximately 24,000 barrels of oil per day. On February 5, 2003, the Venezuelan government imposed currency controls. See *Item 7 – Management's Discussion and Analysis of Financial Conditions and Results of Operations* for a complete description of these events.

As of December 31, 2002, we had total estimated proved reserves, net of minority interest and including our share of equity affiliates, of 127.3 MMBOE, and a standardized measure of discounted future net cash flow, before income taxes, for total proved reserves of $526.7 million. Of these totals, our interests in the South Monagas Unit represented 102.5 MMBOE and $481.3 million, and our equity interest in Geoilbent represented 24.8 MMBbls and $45.4 million, respectively.

As of December 31, 2002, we had total assets of $335.2 million. For the year ended December 31, 2002, we had total revenues of $126.7 million, net cash provided by operating activities of $42.6 million, and long-term debt of $104.7 million. For the year ended December 31, 2001, we had total revenues of $122.4 million, net cash provided by operating activities of $36.6 million, and long-term debt of $221.6 million.

Available Information

We file annual, quarterly, and current reports, proxy statements, and other documents with the SEC under the Securities Act of 1934. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an Internet website that contains reports, proxy and information statements, and other information regarding issuers, including the Company, that file electronically with the SEC. The public can obtain any documents that we file with SEC at http://www.sec.gov.

We also make available, free of charge on or through our Internet website (http://www.harvestnr.com), our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. In addition, the Company has adopted a code of ethics that applies to all of its employees, including its chief executive officer, principal financial officer and principle accounting officer. The text of the code of ethics has been posted on the Governance section of the Company's website.

Operating Strategy

Our business strategy supports the steady investment, prudent risk management and timely development of our large hydrocarbon resources. For the foreseeable future, we believe our best success will be found in Venezuela and Russia, areas in which we have significant experience and expertise. Near term, our strategy is focused on improving the realization of value from our current operations in both Venezuela and Russia. Investments in Venezuela and Russia are exposed to significant political risks.

In Venezuela, we intend to continue to seek cost effective increases in production to extend the life and value of our fields. Completing a gas project in the fourth quarter of 2003 within budget is an important part of this strategy because it creates a new source of revenues from sales of natural gas. We are also looking for ways to diversify our cash flow as events in Venezuela demonstrated the benefits of country risk diversification of our cash flow sources when we lost six weeks of production.

Our Russian operations are an important element of our diversification strategy. We and the majority share owner in Geoilbent continue to strive to improve operations and monetize the value of the fields by lowering operating costs and enhancing financial results. The Geoilbent assets represent significant potential value for us, but remain subject to sub-optimal operating conditions while our lack of majority control over its operations inhibits our ability to implement necessary changes in management, operations or financing matters to fully realize the potential of Geoilbent's assets. In addition, our financial results have been significantly hampered by low Russian domestic oil prices while world oil prices have reached multi-year high levels. Geoilbent's independent accountants have indicated in their report that substantial doubt exists regarding Geoilbent's ability to meet its debts as they become due and continue as a going concern. An important part of our near-term strategy is to establish and implement a plan to maximize the value of our investment in Geoilbent by improving its operations, achieving a control position or selling our minority ownership interest.

We believe that Russia has opportunities and that we, as an independent oil and gas operator, can exploit using Western management and operating techniques. The overall goal is to add undeveloped or underdeveloped resources of oil and gas. Through phased investment, we can then increase and capture the long-term value of the asset. We seek significant, legacy assets, with a controlling ownership interest in partnership with local industry partners. These partners must understand and be familiar with the asset and area's working environment.

Our long-term strategy is founded on three guiding principles: Enable, Manage Risk and Value Harvest. We Enable by using our experience and skills to identify, access and exploit large known resources of hydrocarbons in underexploited areas that can be developed at low overall finding costs, produced at low operating costs and converted into proved reserves, production and value. We Manage Risk by controlling or mitigating the many factors within our control, such as continuing to improve our operating risks, access to markets and financing flexibility. We Value Harvest our existing assets by rapid development to convert underdeveloped hydrocarbons into cash.

We intend to continue to seek and exploit new oil and natural gas reserves in current areas of interest while working toward minimizing the associated financial and operating risks. To reduce these risks, not only in seeking new reserves, but also with respect to our existing operations, we:

- *Focus Our Efforts in Areas of Low Geologic Risk:* We intend to focus our activities only in areas of large known but undeveloped oil and gas resources.

- *Establish a Local Presence Through Joint Venture Partners and the Use of Local Personnel:* We seek to establish a local presence in our areas of operation to facilitate stronger relationships with local government and labor. In addition, using local personnel helps us to take advantage of local knowledge and experience and to minimize costs. In pursuing new opportunities, we will seek to enter at an early stage and find local investment partners in an effort to reduce our risk in any one venture.

- *Commit Capital in a Phased Manner to Limit Total Commitments at Any One Time:* We often agree to minimum capital expenditure or development commitments at the outset of new projects, but we endeavor to structure such commitments so that we can fulfill them over time, thereby limiting our initial cash outlay, as well as maximize the amount of local financing capacity to develop the hydrocarbons and associated infrastructure.

- *Limit Exploration Activities:* We do not engage in exploration except in conjunction with the expansion of an existing reservoir.

Our ability to successfully execute our strategy is subject to significant risks including, among other things, operating risks, political risks and financial risks. Operating risks include our ability to 1) maintain optimal production, 2) achieve maximum reserve recovery and 3) maintain our cost structure on an economically favorable basis, particularly in Geoilbent in which we are a minority owner. Political risks in Venezuela are significant, and while currently partially abated, could again have a negative influence on our operations and our financial flexibility. In Russia, the oil and gas business is evolving, but remains subject to local laws and customs, local market operation and powerful domestic oil and gas companies. Our company is also solely dependent upon sales of oil and gas, once the Venezuelan gas project is completed, to fund our operations and service our debt requirements. Interruptions in Benton-Vinccler's production and cash flow would erode our financial flexibility and hinder our ability to execute our operating strategy. In addition, Venezuela recently imposed foreign currency exchange controls which could increase our costs of operations.

Operations

The following table summarizes our proved reserves, drilling and production activity, and financial operating data by principal geographic area at the end of each of the three years ending December 31, 2002. All Venezuelan reserves are attributable to an operating service agreement between Benton-Vinccler and PDVSA under which all mineral rights are owned by the Government of Venezuela. Geoilbent and Arctic Gas are accounted for under the equity method and have been included at their respective ownership interests in our consolidated financial statements. Our year-end financial information contains results from our Russian operations based on a twelve-month period ending September 30. Accordingly, our results of operations for the years ended December 31, 2002, 2001 and 2000 reflect results from Geoilbent for the twelve months ended September 30, 2002, 2001 and 2000, and from Arctic Gas, until it was sold on April 12, 2002, for the twelve months ended September 30, 2001 and 2000.

We own 80 percent of Benton-Vinccler. The reserve information presented below is net of a 20 percent deduction for the minority interest in Benton-Vinccler. Drilling and production activity and financial data are reflected without deduction for minority interest. Reserves include production projected through the end of the operating service agreement in 2012.

	Benton-Vinccler		
	Year Ended December 31,		
	2002	2001	2000
	(Dollars in 000's)		
RESERVE INFORMATION			
Proved reserves (MBOE)	102,534	83,611	98,431
Discounted future net cash flow attributable to proved reserves, before income taxes	$ 481,284	$ 176,210	$ 368,464
Standardized measure of future net cash flows	$ 317,799	$ 163,328	$ 284,549
DRILLING AND PRODUCTION ACTIVITY:			
Gross wells drilled	13	8	26
Average daily production (Bbls)	26,598	26,788	25,585
FINANCIAL DATA:			
Oil revenues	$ 126,731	$ 122,386	$ 139,890
Expenses:			
Operating expenses and taxes other than on income	31,608	42,175	46,848
Depletion	22,685	21,175	15,708
Income tax expense	4,866	9,083	20,307
Total expenses	59,159	72,433	82,863
Results of operations from oil and natural gas producing activities	$ 67,572	$ 49,953	$ 57,027

We own 34 percent of Geoilbent, which we account for under the equity method. The following table presents our proportionate share of Geoilbent's proved reserves (at September 30 for each respective year), drilling and production activity, and financial operating data for the twelve months ended September 30, 2002, 2001 and 2000.

	Geoilbent		
	Year Ended September 30,		
	2002	2001	2000
	(Dollars in 000's)		
RESERVE INFORMATION			
Proved reserves (MBbls)	25,356	29,668	32,614
Discounted future net cash flow attributable to proved reserves, before income taxes	$ 117,230	$ 81,125	$ 140,160
Standardized measure of future net cash flows	$ 92,939	$ 70,648	$ 114,725
DRILLING AND PRODUCTION ACTIVITY:			
Gross development wells drilled	6	39	39
Net development wells drilled	2	13	13
Average daily production (Bbls)	6,438	4,830	3,945
FINANCIAL DATA:			
Oil and natural gas revenues	$ 31,039	$ 34,261	$ 26,716
Expenses:			
Operating, selling and distribution expenses and taxes other than on income	16,902	16,083	10,831
Depletion	9,237	5,072	3,249
Income tax expense	1,955	3,742	3,306
Total expenses	28,094	24,897	17,386
Results of operations from oil and natural gas producing activities	$ 2,945	$ 9,364	$ 9,330

As of December 31, 2001 and 2000, we owned, free of any sale and transfer restrictions, 39 and 29 percent, respectively, of the equity interests in Arctic Gas, which we account for under the equity method. The following table presents our proportionate share, free of sale and transfer restrictions, of Arctic Gas's proved reserves (at September 30 for each respective year), drilling and production activity, and financial operating data for the period until it was sold on April 12, 2002, and twelve months ended September 30, 2001 and 2000.

	Arctic Gas Company		
	Year Ended September 30,		
	2002	2001	2000
	(Dollars in 000's)		
RESERVE INFORMATION			
Proved reserves (MBOE)	(a)	55,631	41,236
Discounted future net cash flow attributable to proved reserves, before income taxes	(a)	$ 108,400	$ 74,517
Standardized measure of future net cash flows	(a)	$ 82,205	$ 56,880
DRILLING AND PRODUCTION ACTIVITY:			
Gross wells reactivated	(a)	2	4
Average daily production (BOE)	189	502	134
FINANCIAL DATA:			
Oil and natural gas revenues	$ 3,554	$ 4,016	$ 889
Expenses:			
Selling and distribution expenses	1,429	1,165	—
Operating expenses and taxes other than on income	1,673	2,215	604
Depletion	139	311	78
Total expenses	3,241	3,691	682
Results of operations from oil and natural gas producing activities	$ 313	$ 325	$ 207

(a) Arctic Gas was sold on April 12, 2002

South Monagas Unit, Venezuela (Benton-Vinccler)

General

In July 1992, we and Venezolana de Inversiones y Construcciones Clerico, C.A., a Venezuelan construction and engineering company ("Vinccler"), signed a 20-year operating service agreement with Lagoven, S.A., an affiliate of PDVSA, to reactivate and further develop the Uracoa, Tucupita and Bombal fields. These fields comprise the South Monagas Unit. We were the first U.S. company since 1976 to be granted such an oil field development contract in Venezuela.

The oil and natural gas operations in the South Monagas Unit are conducted by Benton-Vinccler, our 80 percent-owned subsidiary. The remaining 20 percent of the outstanding capital stock of Benton-Vinccler is owned by Vinccler. Through our majority ownership of stock in Benton-Vinccler, we make all operational and corporate decisions related to Benton-Vinccler, subject to certain super-majority provisions of Benton-Vinccler's charter documents related to:

- mergers;
- consolidations;
- sales of substantially all of its corporate assets;
- change of business; and
- similar major corporate events.

Vinccler has an extensive operating history in Venezuela. It provided Benton-Vinccler with initial financial assistance and significant construction services. Vinccler continues to provide ongoing assistance with construction projects, governmental relations and labor relations.

Under the terms of the operating service agreement, Benton-Vinccler is a contractor for PDVSA. Benton-Vinccler is responsible for overall operations of the South Monagas Unit, including all necessary investments to reactivate and develop the fields comprising the South Monagas Unit. The Venezuelan government maintains full ownership of all hydrocarbons in the fields. In addition, PDVSA maintains full ownership of equipment and capital infrastructure following its installation.

The operating service agreement provides for Benton-Vinccler to receive an operating fee for each barrel of crude oil delivered. It also provides Benton-Vinccler with the right to receive a capital recovery fee for certain of its capital expenditures, provided that such operating fee and capital recovery fee cannot exceed the maximum total fee per barrel set forth in the agreement. The operating fee is subject to quarterly adjustments to reflect changes in the special energy index of the U.S. Consumer Price Index. The maximum total fee is subject to quarterly adjustments to reflect changes in the average of certain world crude oil prices. Since 1992, the maximum total fee received by Benton-Vinccler has approximated 48 percent of West Texas Intermediate crude oil ("WTI") price.

Benton-Vinccler has constructed a 25-mile oil pipeline from its oil processing facilities at Uracoa to PDVSA's storage facility, the custody transfer point. The operating service agreement specifies that the oil stream may contain no more than one percent base sediment and water. Quality measurements are conducted both at Benton-Vinccler's facilities and at PDVSA's storage facility. In January 2002, Benton-Vinccler installed a continuous flow measuring unit at its facility to closely monitor the quantities of hydrocarbons delivered to PDVSA.

At the end of each quarter, Benton-Vinccler prepares an invoice to PDVSA based on barrels of oil accepted by PDVSA during the quarter, using quarterly adjusted contract service fees per barrel. Payment is due under the invoice by the end of the second month after the end of the quarter. Invoice amounts and payments are denominated in U.S. dollars. Payments are wire transferred into Benton-Vinccler's account in a commercial bank in the United States. While PDVSA has timely paid its past invoices, payment of the invoice for the fourth quarter 2002 deliveries was seven days late. PDVSA indicated that the late payment was due to business interruptions resulting from the national civil work stoppage in Venezuela.

Natural Gas Sales Contract

On September 19, 2002, Benton-Vinccler and PDVSA signed an amendment to the operating service agreement, providing for the delivery of up to 198 Bcf of natural gas through July 2012 at a price of $1.03 per Mcf. Natural gas sales are expected to commence at a rate of 40 to 50 MMcf of natural gas per day in the fourth quarter of 2003 and gradually increase up to 70 MMcfpd in 12 to 18 months from the initial sale. In addition, Benton-Vinccler agreed to sell to PDVSA 4.5 million barrels of oil at $7.00 per barrel beginning with our first gas sale. Initial gas production will come from Uracoa, which allows us to more efficiently manage the reservoir and eliminate the restrictions on producing oil wells with high gas to oil ratios. The gas reserves in Bombal will be used to meet the future terms of the gas contract in 2005 or 2006.

An initial capital investment of approximately $26 million will be required to build a 64-mile pipeline with a normal capacity of 70 MMcf of natural gas per day and a design capacity of 90 MMcf of natural gas per day, a gas gathering system, upgrades to the UM-2 plant facilities and new gas treatment and compression facilities. We plan to start fabrication and construction process for the gas pipeline in early 2003. Benton-Vinccler has borrowed $15.5 million under a project loan for the gas pipeline and related facilities and the remainder will be funded from existing cash balances and internally generated cash flow.

Location and Geology

The South Monagas Unit extends across the southeastern part of the state of Monagas and the southwestern part of the state of Delta Amacuro in eastern Venezuela. The South Monagas Unit is approximately 51 miles long and eight miles wide and consists of 157,843 acres, of which the fields comprise approximately one-half of the acreage. At December 31, 2002, proved reserves attributable to our Venezuelan operations were 128,168 MBOE (102,534 MBOE net to Harvest). This represented approximately 80 percent of our proved reserves at year end. Benton-Vinccler has been primarily developing the Oficina sands in the Uracoa Field. The Uracoa Field contains 62 percent of the South Monagas Unit's proved reserves. Benton-Vinccler is currently reinjecting most of the associated natural gas produced at Uracoa back into the reservoir.

Drilling and Development Activity

Benton-Vinccler drilled 11 oil and 2 water injection wells in 2002 and had an average of 131 wells on production in all fields in 2002.

Uracoa Field

Benton-Vinccler has been developing the South Monagas Unit since 1992, beginning with the Uracoa Field.

Benton-Vinccler processes the oil, water and natural gas produced from the Uracoa Field in the Uracoa central processing unit. Benton-Vinccler ships the processed oil via pipeline to the PDVSA custody transfer point. Benton-Vinccler treats and filters produced water, and then re-injects it into the aquifer to assist the natural water drive. Benton-Vinccler re-injects natural gas into the natural gas cap primarily for storage conservation. The major components of the state-of-the-art process facility were designed in the United States and installed by Benton-Vinccler. This process design is commonly used in heavy oil production in the United States, but was not previously used extensively in Venezuela to process crude oil of similar gravity or quality. The current production facility has capacity to handle 60 MBbls of oil per day, 130 MBbls of water per day, and 40 to 45 MMcf of natural gas per day.

In August 1999, Benton-Vinccler sold its power generation facility located in the Uracoa Field for $15.1 million. Concurrently with the sale, Benton-Vinccler entered into a long-term power purchase agreement with the purchaser of the facility to provide for the electrical needs of the field throughout the remaining term of the operating service agreement.

Tucupita and Bombal Fields

In 2001, Benton-Vinccler reactivated nine wells in Tucupita and in 2002 completed eleven oil producers and two water injectors. The oil is transported through a 31-mile, 20 MBbl per day capacity oil pipeline constructed in 2001 from Tucupita to the Uracoa central processing unit.

Benton-Vinccler is reinjecting produced water from Tucupita into the aquifer to aid the natural water drive and we utilize a portion of the associated natural gas to operate a power generation facility to supply our power needs.

To date, we have drilled one well in the Bombal Field and reactivated another.

Customers and Market Information

Under the operating service agreement, oil produced is delivered to PDVSA for an operating fee. From December 14, 2002 through February 6, 2003, no sales were made because of PDVSA's inability to accept our oil due to the national civil work stoppage in Venezuela. As a result, 2002 sales were reduced by approximately 550,000 barrels. In restoring production, we encountered problems with some of our wells, but we do not believe the associated costs will be material. By the end of March 2003, our average production was approximately 24,000 barrels of oil per day. While we have substantial cash reserves, a prolonged loss of sales could have a material adverse effect on our financial condition.

Employees and Community Relations

Benton-Vinccler has a highly skilled staff of 172 local employees and 5 expatriates and has also formed successful and supportive relationships with local government agencies and communities.

Benton-Vinccler has invested in a Social Community Program that includes medical programs in ophthalmologic and dental care, as well as additional social investments including the purchase of medicines and medical equipment in local communities within the South Monagas Unit.

Health, Safety and Environment

Benton-Vinccler's health, safety and environmental policy is an integral part of its business. Annually, Benton-Vinccler continually improves its policy and practices related to personnel safety, property protection and environmental management. These improvements can be directly attributed to the efforts in accident prevention programs and the training and implementation of a comprehensive Process Safety Management System.

North Gubkinskoye and South Tarasovskoye, Russia (Geoilbent)

General

In December 1991, the joint venture agreement forming Geoilbent was registered with the Ministry of Finance of the USSR. In November 1993, the agreement was registered with the Russian Agency for International Cooperation and Development. Geoilbent was later re-chartered as a limited liability company. Purneftegazgeologia and Purneftegaz (co-founding shareholders) contributed their interest to Open Joint Stock Company Minley ("Minley") in 2001. Geoilbent's current ownership is as follows:

- Harvest — 34 percent.
- Minley — 66 percent.

We believe that we have developed a good relationship with Minley and have not experienced any disagreements on major operational matters. We are reviewing ways to improve the operations, but as a minority shareholder we may not be able to fully effect changes in operations, if indicated as necessary or desirable by our review. Geoilbent shareholder action requires a 67 percent majority vote of its shareholders.

Geoilbent's oil and gas fields are situated on land belonging to the Russian Federation. Geoilbent obtained licenses from the local authorities and pays unified production taxes to explore and produce oil and gas from these fields. Licenses will expire in September 2018 for the North Gubkinskoye field, and in March 2023 for the South Tarasovskoye field. However, under Paragraph 4 of the Russian Federal Law 20-FZ, dated January 2, 2000, the license may be extended over the economic life of the lease at Geoilbent's option. Geoilbent intends to extend such licenses for properties that are expected to produce subsequent to their expiry dates. Estimates of proved reserves extending past the license expiration currently represent approximately 5 percent of total proved reserves.

Location and Geology

Geoilbent develops, produces and markets crude oil from the North Gubkinskoye and South Tarasovskoye Fields in the West Siberia region of Russia, located approximately 2,000 miles northeast of Moscow. Large proved oil and gas fields surround all four of Geoilbent's licenses.

The North Gubkinskoye Field is included inside a license block of 167,086 acres, an area approximately 15 miles long and four miles wide. The field has been delineated with over 60 exploratory wells, which tested 26 separate reservoirs. The field is a large anticlinal structure with multiple pay sands. The development to date has focused on the Cretaceous BP 8, 9, 10, 11 and 12 reservoirs with minor development in the BP 6, 7 and Jurassic reservoirs. Geoilbent is currently flaring the produced natural gas in accordance with environmental regulations, although it is exploring alternatives to construct a natural gas processing plant and to market the natural gas and natural gas liquids.

The South Tarasovskoye Field is located southeast of North Gubkinskoye Field and straddles the eastern boundary of the Urabor Yakhinsky exploration block acquired by Geoilbent in 1998. It is estimated that a majority of the field is situated within the block. The remaining portion of the field falls within a license block owned by Purneftegaz. Production began in early 2001 from a discovery well drilled close to the boundary by Purneftegaz. Only 521 of Geoilbent's 763,558 acres in this field are reflected as proved-developed acres. The development to date has focused on the Cretaceous BP 7, 8, 9 and 10, and the Jurassic reservoirs. All of the current production in South Tarasovskoye is achieved from the main anticlinal feature.

Geoilbent also holds rights to two more license blocks comprising 426,199 acres in the West Siberia region of Russia.

Drilling, Development, Customer and Market Information

Currently there are 109 wells in production in North Gubkinskoye and 18 in production in South Tarasovskoye. In addition, there are 37 and 2 injectors, respectively, currently injecting water in each field.

Until Geoilbent began operations in 1992, the North Gubkinskoye Field was one of the largest non-producing oil and gas fields in the region. Geoilbent transports its oil production to Transneft, the state oil pipeline monopoly. Transneft then transports the oil to the western border of Russia for export sales or to various domestic locations for non-export sales. Trading companies such as Rosneftegasexport handles all export oil sales, which are paid in US dollars into Geoilbent's bank account. In 2002, approximately 34% of Geoilbent's production was sold in the world export market and 66% in the domestic Russian market. Geoilbent's domestic Russian crude oil price declines significantly in the winter months. For example, during the period from September 30, 2002 until December 31, 2002. In this same period, Russian export prices increased from approximately $20 to $29 per barrel, however, Geoilbent's average price declined $5.05 in value between these two periods. Geoilbent could not export more crude oil due to Transneft and the winter export limitations.

Geoilbent is continuing to pursue its oil development program. The current production facilities are operating at or near capacity and will need to be expanded to accommodate future production increases. Currently gas production from North Gubkinskoye is consumed as fuel with the remainder being flared.

In 1996, Geoilbent secured a loan from the European Bank for Reconstruction and Development ("EBRD") to develop a portion of the oil and condensate reserves of the North Gubkinskoye Field. The outstanding debt balance of $22 million on the debt to EBRD has been restructured into a new $50 million loan facility, which will be used to reduce payables and implement the South Tarasovskoye oil development in 2003. On March 12, 2003 Geoilbent drew $8.0 million under the loan to reduce payables. However, there can be no assurance that this draw on the credit facility will be adequate to permit Geoilbent to meet the current financial ratio requirement under the credit facility. If Geoilbent fails to meet the ratio requirements for two consecutive quarters it will result in an event of default whereby EBRD may, at its option, demand payment of the outstanding principal and interest. In addition, the restructured loan agreement requires that Geoilbent implement a new management information system by May 1, 2003. Geoilbent will be unable to timely satisfy this requirement which also results in an event of default whereby EBRD may, at its option, demand payment of the outstanding principal and interest. For a more complete description of the terms and conditions of the EBRD loan and Geoilbent's covenant obligations, *See Item 7 – Risk Factors and Note 9 – Russian Operations.*

Employees, Community and Country Relations

Geoilbent employs six expatriates working with Geoilbent and 700 local employees. We have conducted community relations programs, providing medical care, training, equipment and supplies in towns in which Geoilbent personnel reside and also for the nomadic indigenous population which resides in the area of oilfield operations.

East Urengoy, Russia (Arctic Gas Company)

Arctic Gas Company was sold in April 2002. *See Note 9 – Russian Operations.*

WAB-21, South China Sea (Benton Offshore China Company)

General

In December 1996, we acquired Crestone Energy Corporation, subsequently renamed Benton Offshore China Company. Its principal asset is a petroleum contract with China National Offshore Oil Corporation ("CNOOC") for the WAB-21 area. The WAB-21 petroleum contract covers 6.2 million acres in the South China Sea, with an option for an additional 1.25 million acres under certain circumstances, and lies within an area which is the subject of a territorial dispute between the People's Republic of China and Vietnam. Vietnam has executed an agreement on a portion of the same offshore acreage with another company. The territorial dispute has lasted for many years, and there has been limited exploration and no development activity in the area under dispute. As part of our review of Company assets, we conducted a third-party evaluation of the WAB-21 area. Through that evaluation and our own assessment, we recorded a $13.4 million impairment charge in the second quarter of 2002.

Location and Geology

The WAB-21 contract area is located approximately 50 miles southeast of the Dai Hung (Big Bear) Oil Field. The block is adjacent to British Petroleum's giant natural gas discovery at Lan Tay (Red Orchid) and 100 miles north of Exxon's Natuna Discovery. The contract area covers several similar structural trends, each with potential for hydrocarbon reserves in possible multiple pay zones.

Drilling and Development Activity

Due to the sovereignty issues between China and Vietnam, we have been unable to pursue an exploration program during phase one of the contract. As a result, we have obtained a license extension, with the current extension in effect until May 31, 2005.

Domestic Operations

We had a 35 percent working interest in the Lakeside Exploration Prospect, Cameron Parish, Louisiana. In September 2002, we determined the Claude Boudreaux #1 exploratory well was not prospective for hydrocarbons and assigned our entire interest in the Lakeside Exploration Prospect to a third party and recognized a $1.1 million impairment.

We acquired a 100 percent interest in three California State offshore oil and gas leases ("California Leases") and a parcel of onshore property from Molino Energy Company, LLC. All capitalized costs associated with the California Leases have been fully impaired. The California Leases have expired and the Company has issued the required quitclaim deed, is plugging and abandoning the previously drilled exploratory wells and will undertake any required lease and land reclamation. It is believed that these costs will not be material.

Activities by Area

The following table summarizes our consolidated activities by area. Total Assets represents all assets including long-lived assets accounted for under the equity method:

(in thousands)	Venezuela	Other Foreign	Total Foreign	United States	Total Assets
Year ended December 31, 2002					
Oil sales	$126,731		$126,731		$126,731
Total Assets	$209,733	$52,302	$262,035	$73,157	$335,192
Year ended December 31, 2001					
Oil sales	$122,386		$122,386		$122,386
Total Assets	$167,671	$100,801	$268,472	$79,679	$348,151
Year ended December 31, 2000					
Oil and natural gas sales	$139,890		$139,890	$ 394	$140,284
Total Assets	$166,462	$ 78,406	$244,868	$41,579	$286,447

Reserves

Estimates of our proved reserves as of December 31, 2002 and 2001 were prepared by Ryder Scott Company, L.P., independent petroleum engineers. The following table sets forth information regarding estimates of proved reserves at December 31, 2002. The Venezuelan information includes reserve information net of a 20 percent deduction for the minority interest in Benton-Vinccler. All Venezuelan reserves are attributable to an operating service agreement between Benton-Vinccler and PDVSA under which all mineral rights are owned by the Government of Venezuela. Russia's reserves reflect our 34 percent equity interest in Geoilbent. Although we estimate there are substantial natural gas reserves in the license blocks held by Geoilbent, no natural gas reserves have been recorded as of December 31, 2002 because of a lack of sales and transportation contracts in place.

	Net Crude Oil and Condensate (MBbls)		
	Proved Developed	Proved Undeveloped	Total
Venezuela	43,066	33,069	76,135
Russia	11,840	12,941	24,781
Total	54,906	46,010	100,916

	Net Natural Gas (MMcf)		
	Proved Developed	Proved Undeveloped	Total
Venezuela	84,000	74,400	158,400

Estimates of commercially recoverable oil and natural gas reserves and of the future net cash flows derived there from are based upon a number of variable factors and assumptions, such as:

- historical production from the subject properties;
- comparison with other producing properties;
- the assumed effects of regulation by governmental agencies; and
- assumptions concerning future operating costs, severance and excise taxes, export tariffs, abandonment costs, development costs, workover and remedial costs, all of which may vary considerably from actual results.

All such estimates are to some degree speculative and various classifications of reserves are only attempts to define the degree of speculation involved. For these reasons, estimates of the commercially recoverable reserves of oil attributable to any particular property or group of properties, the classification, cost and risk of recovering such reserves and estimates of the future net cash flows expected there from, prepared by different engineers or by the same engineers at different times may vary substantially. The difficulty of making precise estimates is accentuated by the fact that 46 percent of our total proved reserves were undeveloped as of December 31, 2002.

The following costs therefore will likely vary from our estimates and such variances may be material:

- severance and excise taxes;
- export tariffs;
- development expenditures;
- workover and remedial expenditures;
- abandonment expenditures; and
- operating expenditures.

Reserve estimates are not constrained by the availability of the capital resources required to finance the estimated development and operating expenditures. In addition, actual future net cash flows will be affected by factors such as:

- actual production;
- oil sales;
- supply and demand for oil and natural gas;
- availability and capacity of gathering systems and pipelines;
- changes in governmental regulations or taxation; and
- the impact of inflation on costs.

The timing of actual future net oil and natural gas sales from proved reserves as well as the year-end price, and thus their actual present value, can be affected by the timing of the incurrence of expenditures in connection with development of oil and gas properties. The 10 percent discount factor required by the SEC to be used to calculate present value for reporting purposes is not necessarily the most appropriate discount factor based on interest rates in effect from time to time, risks associated with the oil and natural gas industry and the political risks associated with operations in Venezuela and Russia. Discounted present value, regardless of what discount rate is used, is materially affected by assumptions as to the amount and timing of future production, which assumptions may and often do prove to be inaccurate. For the period ending December 31, 2002, we reported $526.7 million of discounted future net cash flows before income taxes from proved reserves based on the SEC's required calculations.

Production, Prices and Lifting Cost Summary

In the following table we have set forth by country our net production, average sales prices and average operating expenses for the years ended December 31, 2002, 2001 and 2000. The presentation for Venezuela includes 100 percent of the production, without deduction for minority interest. Geoilbent (34 percent ownership) and Arctic Gas (39 and 29 percent ownership not subject to any sale or transfer restrictions at December 2001 and 2000, respectively), which are accounted for under the equity method, have been included at their respective ownership interest in the consolidated financial statements based on a fiscal period ending September 30 and, accordingly, our results of operations for the years ended December 31, 2002, 2001 and 2000 reflect results from Geoilbent for the twelve months ended September 30, 2002, 2001 and 2000, and from Arctic Gas until it was sold on April 12, 2002, and for the twelve months ended September 30, 2001 and 2000.

	Year Ended December 31,		
	2002	2001	2000
Venezuela			
Crude Oil Production (Bbls)	9,708,295	9,777,516	9,364,088
Average Crude Oil Sales Price ($ per Bbl)	$ 13.08	$ 12.52	$ 14.94
Average Operating Expenses ($ per Bbl)	$ 3.26	$ 4.30	$ 5.01
Geoilbent(a)			
Net Crude Oil Production (Bbls)	2,349,916	1,762,814	1,444,181
Average Crude Oil Sales price ($ per Bbl)	$ 13.21	$ 19.51	$ 18.54
Average Operating Expenses ($ per Bbl)	$ 2.09	$ 2.17	$ 2.31
Arctic Gas (a)(b)			
Net Crude Oil Production (Bbls)	(b)	183,087	48,833
Average Crude Oil Sales price ($ per Bbl)	(b)	$ 21.93	$ 18.20
Average Operating Expenses ($ per Bbl)	(b)	$ 7.42	$ 5.97

(a) Information represents our ownership interest.
(b) Arctic Gas was sold on April 12, 2002.

Regulation

General

Our operations are affected by political developments and laws and regulations in the areas in which we operate. In particular, oil and natural gas production operations and economics are affected by:

- change in governments;
- civil unrest;
- price and currency controls;
- limitations on oil and natural gas production;
- world demand for crude oil;
- tax and other laws relating to the petroleum industry;
- changes in such laws; and
- changes in administrative regulations and the interpretation and application of such rules and regulations.

In any country in which we may do business, the oil and natural gas industry legislation and agency regulation are periodically changed for a variety of political, economic, environmental and other reasons. Numerous governmental departments and agencies issue rules and regulations binding on the oil and natural gas industry, some of which carry substantial penalties for the failure to comply. The regulatory burden on the oil and natural gas industry increases our cost of doing business.

Venezuela

On February 5, 2003, Venezuela imposed currency controls and created the Commission for Administration of Foreign Currency ("CADIVI") with the task of establishing the detailed rules and regulations and generally administering the exchange control regime. These controls fix the exchange rate between the Bolivar and the U.S. dollar, and restrict the ability to exchange Bolivars for dollars and vice versa. Oil companies such as Benton-Vinccler are allowed to receive payments for oil sales in U.S. currency and pay dollar-denominated debt, dividends and expenses from those payments. We are unable to predict the impact of the currency controls on us or Benton-Vinccler because the CADIVI has not issued final regulations. The near-term effect has been to restrict Benton-Vinccler's ability to make payments to employees and vendors in Bolivars, causing it to borrow money on a short-term basis to meet these obligations. As of March 14, 2003, these short-term borrowings have been repaid and while we now have Bolivars to meet our current obligations, the situation could change. In addition, the currency controls have increased the cost of Benton-Vinccler's Bolivar denominated debt. We plan to prepay the Bolivar denominated debt as of March 31, 2003.

Venezuela requires environmental and other permits for certain operations conducted in oil field development, such as site construction, drilling, and seismic activities. As a contractor to PDVSA, Benton-Vinccler submits capital budgets to PDVSA for approval including capital expenditures to comply with Venezuelan environmental regulations. No capital expenditures to comply with environmental regulations were required in 2002. Benton-Vinccler also submits requests for permits for drilling, seismic and operating activities to PDVSA, which then obtains such permits from the Ministry of Energy and Mines and Ministry of Environment, as required. Benton-Vinccler is also subject to income, municipal and value-added taxes, and must file certain monthly and annual compliance reports to the national tax administration and to various municipalities.

Russia

Geoilbent submits annual production and development plans, which include information necessary for permits and approvals for its planned drilling, seismic and operating activities, to local and regional governments and to the Ministry of Fuel and Energy and the Ministry of Natural Resources. Geoilbent submits annual production targets and quarterly export nominations for oil pipeline transportation capacity to the Ministry of Fuel and Energy. Geoilbent is subject to customs, value-added and municipal and income taxes. Various municipalities and regional tax inspectorates are involved in the assessment and collection of these taxes. Geoilbent must file operating and financial compliance reports with several agencies, including the Ministry of Fuel and Energy, Ministry of Natural Resources, Committee for Technical Mining Monitoring and the State Customs Committee.

Effective in August 2001, a new tariff structure on exported oil was instituted. The Russian government sets the maximum crude oil export tariff rate as a percentage of the customs dollar value of Urals, Russia's main crude export blend. Under the current system when the Urals price is in a range of $109.50 to $182.50 per ton ($15 to $25 per Bbl) a tariff of 35 percent is imposed on the sum exceeding the level of $109.50. When Urals crude is below $109.50 per ton no tariff is collected. When the price rises above $182.50 per ton, exporters pay a combined tariff comprising $25.53 per ton, plus a tariff of 40 percent on the sum exceeding $182.50. By way of example, a $27.00 Ural price per barrel would incur an export tariff of $4.28 per barrel. Effective January 1, 2002, mineral restoration tax, royalty tax and excise tax on crude oil production were abolished and replaced by the unified natural resources production tax. Through December 31, 2004, the base rate for the unified natural resources production tax is set at Russian Rubles 340 per metric ton of crude oil produced and is to be adjusted on the market price of Urals blend and the Russian Ruble/US Dollar exchange rate. The tax rate is zero if the Urals blend price falls to or below $8.00 per barrel. From January 1, 2005, the unified natural resources production tax rate is set by law at 16.5 percent of crude oil revenues recognized by Geoilbent based on Regulations on Accounting and Reporting of the Russian Federation. We are unable to predict the impact of future taxes, duties and other burdens on Geoilbent's operations.

Drilling and Undeveloped Acreage

For acquisitions of leases and producing properties, development and exploratory drilling, production facilities and additional development activities such as workovers and recompletions, we spent approximately (excluding our share of capital expenditures incurred by equity affiliates):

- $51 million during 2002;
- $44 million during 2001; and
- $50 million during 2000;

We have drilled or participated through our equity affiliate in the drilling of wells as follows:

	Year Ended December 31,					
	2002		2001		2000	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Exploration:						
Dry hole	1	0.4	—	—	—	—
Development:						
Crude oil	17	10.8	20	10.5	65	34.1
Total	18	11.2	8	10.5	65	34.1
Average Depth of Wells (Feet)		7,341		6,043		7,048
Producing Wells (1):						
Crude Oil	258	158.2	274	169.9	268	163.6

(1) The information related to producing wells reflects wells we drilled, wells we participated in drilling and producing wells we acquired.

In 2002, Geoilbent participated in the drilling of six crude oil wells.

All of our drilling activities are conducted on a contract basis with independent drilling contractors. We do not directly operate any drilling equipment.

Acreage

The following table summarizes the developed and undeveloped acreage that we owned, leased or held under operating service agreement or concession as of December 31, 2002:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Venezuela (Benton-Vinccler)	10,966	8,773	146,877	117,502
Russia (Geoilbent)	36,697	12,477	1,320,146	448,850
China	—	—	7,470,080	7,470,080
Total	47,663	21,250	8,937,103	8,036,432

Competition

We encounter strong competition from major oil and gas companies and independent operators in acquiring properties and leases for exploration for crude oil and natural gas. The principal competitive factors in the acquisition of such oil and gas properties include political, staff and data necessary to identify, investigate and purchase such leases, and the financial resources necessary to acquire and develop such leases. Many of our competitors have financial resources, staffs, data resources and facilities substantially greater than ours.

Environmental Regulation

Various federal, state, local and international laws and regulations relating to the discharge of materials into the environment, the disposal of oil and natural gas wastes, or otherwise relating to the protection of the environment, may affect our operations and costs. We are committed to the protection of the environment and believe we are in substantial compliance with the applicable laws and regulations. However, regulatory requirements may, and often do, change and become more stringent, and there can be no assurance that future regulations will not have a material adverse effect on our financial position.

Employees

At December 31, 2002, we had 19 full-time employees, augmented from time-to-time with independent consultants, as required. Benton-Vinccler had 172 and Geoilbent had 700 local employees.

Title to Developed and Undeveloped Acreage

All Venezuelan reserves are attributable to an operating service agreement between Benton-Vinccler and PDVSA, under which all mineral rights are owned by the Government of Venezuela. With regard to Russian acreage, Geoilbent has obtained license agreements and other documentation from appropriate regulatory agencies in Russia which we believe is adequate to establish their right to develop, produce and market oil and natural gas from their fields.

The WAB-21 petroleum contract lies within an area which is the subject of a territorial dispute between the People's Republic of China and Vietnam. Vietnam has executed an agreement on a portion of the same offshore acreage with a third party. The territorial dispute has existed for many years, and there has been limited exploration and no development activity in the area under dispute. It is uncertain when or how this dispute will be resolved, and under what terms the various countries and parties to the agreements may participate in the resolution.

Glossary

When the following terms are used in the text they have the meanings indicated.

Mcf. "Mcf" means thousand cubic feet. "Mmcf" means million cubic feet. "Bcf" means billion cubic feet.

Bbl. "Bbl" means barrel. "Bbls" means barrels. "MBbls" means thousand barrels. "MMBbls" means million barrels.

BOE. "BOE" means barrels of oil equivalent, which are determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas so that six Mcf of natural gas is referred to as one barrel of oil equivalent or "BOE". "MBOE" means thousands of barrels of oil equivalent. "MMBOE" means millions of barrels of oil equivalent.

Capital Expenditures. "Capital Expenditures" means costs associated with exploratory and development drilling (including exploratory dry holes); leasehold acquisitions; seismic data acquisitions; geological, geophysical and land-related overhead expenditures; delay rentals; producing property acquisitions; and other miscellaneous capital expenditures.

Completion Costs. "Completion Costs" means, as to any well, all those costs incurred after the decision to complete the well as a producing well. Generally, these costs include all costs, liabilities and expenses, whether tangible or intangible, necessary to complete a well and bring it into production, including installation of service equipment, tanks, and other materials necessary to enable the well to deliver production.

Development Well. A "Development Well" is a well drilled as an additional well to the same reservoir as other producing wells on a lease, or drilled on an offset lease not more than one location away from a well producing from the same reservoir.

Exploratory Well. An "Exploratory Well" is a well drilled in search of a new and as yet undiscovered pool of oil or natural gas, or to extend the known limits of a field under development.

Finding Cost. "Finding Cost", expressed in dollars per BOE, is calculated by dividing the amount of total capital expenditures related to acquisitions, exploration and development costs (reduced by proceeds for any sale of oil and gas properties) by the amount of total net reserves added or reduced as a result of property acquisitions and sales, drilling activities and reserve revisions during the same period.

Future Development Cost. "Future Development Cost" of proved nonproducing reserves, expressed in dollars per BOE, is calculated by dividing the amount of future capital expenditures related to development properties by the amount of total proved non-producing reserves associated with such activities.

Gas Cap. "Gas Cap" is the natural gas trapped above the oil in a reservoir.

Gross Acres or Wells. "Gross Acres or Wells" are the total acres or wells, as the case may be, in which an entity has an interest, either directly or through an affiliate.

Net Acres or Wells. A party's "Net Acres" or "Net Wells" are calculated by multiplying the number of gross acres of gross wells in which that party has an interest by the fractional interest of the party in each such acre or well.

Operating Expenses. "Operating Expenses" are the expenses of lifting oil from a producing formation to the surface, consisting of the costs incurred to operate and maintain wells and related equipment and facilities, including labor costs, repair and maintenance, supplies, insurance, production and severance taxes.

Producing Properties or Reserves. "Producing Reserves" are Proved Developed Reserves expected to be produced from existing completion intervals now open for production in existing wells. "Producing Properties" are properties to which Producing Reserves have been assigned by an independent petroleum engineer.

Proved Developed Reserves. "Proved Developed Reserves" are Proved Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. "Proved Reserves" are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and natural gas reservoirs under existing economic and operating conditions, that is, on the basis of prices and costs as of the date the estimate is made and any price changes provided for by existing conditions.

Proved Undeveloped Reserves. "Proved Undeveloped Reserves" are Proved Reserves which can be expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Reserves. "Reserves" means crude oil and natural gas, condensate and natural gas liquids, which are net of leasehold burdens, are stated on a net revenue interest basis, and are found to be commercially recoverable.

Standardized Measure of Future Net Cash Flows. The "Standardized Measure of Future Net Cash Flows" is a method of determining the present value of Proved Reserves. The future net oil sales from Proved Reserves are estimated assuming that oil and natural gas prices and production costs remain constant. The resulting stream of oil sales is then discounted at the rate of 10 percent per year to obtain a present value.

Undeveloped Acreage. "Undeveloped Acreage" is oil and natural gas acreage on which wells have not been drilled or completed to a point that would permit commercial production regardless of whether such acreage contains proved reserves.

Item 2. Properties

In July 2001, we leased office space in Houston, Texas for three years for approximately $11,000 per month. We lease 17,500 square feet of space in a California building that we no longer occupy under a lease agreement that expires in December 2004; all of this office space has been subleased for rents that approximate our lease costs.

Item 3. Legal Proceedings

See *Note 13 – Related Party Transactions* regarding the A. E. Benton proceeding. The Company is a defendant in or otherwise involved in litigation incidental to its business. In the opinion of management, there is no litigation which is material to the Company.

Item 4. Submission of Matters to a Vote of Security Holders

None

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

PRICE RANGE OF COMMON STOCK AND DIVIDEND POLICY

Our Common Stock has traded on the New York Stock Exchange ("NYSE") since May 20, 2002 under the symbol "HNR". Prior to that date it traded under the symbol "BNO". As of December 31, 2002, there were 35,248,296 shares of common stock outstanding, with approximately 866 stockholders of record. The following table sets forth the high and low sales prices for our Common Stock reported by the NYSE.

Year	Quarter	High	Low
2001			
	First quarter	2.44	1.56
	Second quarter	2.46	1.55
	Third quarter	1.85	1.00
	Fourth quarter	1.65	1.10
2002			
	First quarter	4.03	1.43
	Second quarter	5.00	3.77
	Third quarter	5.43	3.21
	Fourth quarter	7.54	5.50

On March 21, 2003, the last sales price for the common stock as reported by the NYSE was $4.40 per share.

Our policy is to retain earnings to support the growth of our business. Accordingly, our Board of Directors has never declared a cash dividend on our common stock and our indenture currently restricts the declaration and payment of any cash dividends.

Item 6. Selected Financial Data

SELECTED CONSOLIDATED FINANCIAL DATA

The following table sets forth our selected consolidated financial data for each of the years in the five-year period ended December 31, 2002. The selected consolidated financial data have been derived from and should be read in conjunction with our annual audited consolidated financial statements, including the notes thereto. Our year-end financial information contains results from our Russian operations through our equity affiliates based on a twelve-month period ending September 30. Accordingly, our results of operations for the years ended December 31, 2002, 2001, 2000, 1999 and 1998 reflect results from Geoilbent for the twelve months ended September 30, 2002, 2001, 2000, 1999 and 1998, and from Arctic Gas (until sold on April 12, 2002) for the twelve months ended September 30, 2002, 2001, 2000, 1999 and 1998.

	Year Ended December 31,				
	2002	2001	2000	1999	1998
	(in thousands, except per share data)				
Statement of Operations:					
Total revenues	$ 126,731	$ 122,386	$ 140,284	$ 89,060	$ 82,212
Operating income (loss)	34,585	28,201	53,204	(22,525)	(210,066)
Income (loss) before minority interests	109,516	42,880	23,044	(34,216)	(201,413)
Net income (loss) per common share:					
Basic	$ 2.90	$ 1.27	$ 0.67	$ (1.09)	$ (6.21)
Diluted	$ 2.78	$ 1.27	$ 0.66	$ (1.09)	$ (6.21)
Weighted average common shares outstanding					
Basic	34,637	33,937	30,724	29,577	29,554
Diluted	36,130	34,008	30,890	29,577	29,554

	Year Ended December 31,				
	2002	2001	2000	1999	1998
	(in thousands)				
Balance Sheet Data:					
Working capital (deficit)	$ 97,001	$ (586)	$ 12,370	$ 32,093	$ 60,927
Total assets	335,192	348,151	286,447	276,311	324,363
Long-term obligations, net of current maturities	104,700	221,583	213,000	264,575	280,002
Stockholders' equity (deficit) [1]	171,317	67,623	12,904	(17,178)	12,989

(1) No cash dividends were paid during the periods presented.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Risk Factors

In addition to the other information set forth elsewhere in this Form 10-K, the following factors should be carefully considered when evaluating the Company.

OUR CONCENTRATION OF ASSETS IN VENEZUELA INCREASES OUR EXPOSURE TO PRODUCTION DECLINES AND DISRUPTIONS. During 2002, the production from the South Monagas Unit in Venezuela represented all of our total production from consolidated companies. Our production, revenue and cash flow will be adversely affected if production from the South Monagas Unit decreases significantly for any reason. From December 14, 2002 through February 6, 2003, no sales were made because of PDVSA's inability to accept our oil due to the national civil work stoppage in Venezuela. As a result, 2002 sales were reduced by approximately 550,000 barrels and sales in 2003 were reduced by an estimated 1.2 million barrels. While the situation has stabilized and production is returning to normal, there continues to be political and economic uncertainty that could lead to another disruption of our sales. In restoring production, we encountered problems with some wells, but we do not believe the associated costs will be material. By the end of March 2003, our average production was approximately 24,000 barrels of oil per day. As a result of the national civil work stoppage, the Government of Venezuela terminated several thousand PDVSA employees and announced a decentralization of PDVSA's operations. While the effect of these changes cannot be predicted, it could adversely affect PDVSA's ability to manage its contracts and meet its obligations with its suppliers and vendors, such as Benton-Vinccler. As a result of the situation in PDVSA, its payment to Benton-Vinccler for crude delivered in the fourth quarter 2002 was late by seven days. We believe that the payment demonstrates PDVSA's commitment to building its production levels back to full capacity and returning to more normalized business relations with its customers and suppliers. While we have substantial cash reserves to withstand a future disruption, a prolonged loss of sales or a failure or delay by PDVSA to pay our invoices could have a material adverse effect on our financial condition. We have been required to curtail sales to PDVSA in April and December 2002 due to insufficient crude oil storage capacity. We have never been required to curtail sales before 2002. We cannot be assured that our sales to PDVSA will not be curtailed in the future in the same manner.

GEOILBENT'S LIQUIDITY COULD LIMIT ITS ABILITY TO MAINTAIN OR INCREASE PRODUCTION.

Ability to comply with credit facility. The $50 million revolving credit agreement with EBRD requires that Geoilbent meet certain covenants which include, among other things, the maintenance of financial ratios. If Geoilbent fails to meet the ratio requirements for two consecutive quarters it will result in an event of default whereby EBRD may, at its option, demand payment of the outstanding principal and interest. In addition, the loan agreement requires that Geoilbent implement a new management information system by May 1, 2003. If Geoilbent is unable to timely satisfy this requirement, it also results in an event of default whereby EBRD may, at its option, demand payment of the outstanding principal and interest. Any event of default also gives EBRD the right to exercise its security interest in the assets of Geoilbent and, under a share pledge agreement, our ownership interest in Geoilbent. An event of default could also limit Geoilbent's ability to access additional funds under the EBRD facility. It is unlikely that Geoilbent will be able to timely implement a new management information system as required by the EBRD loan facility. Further, while on March 12, 2003, Geoilbent has drawn down $8 million on the EBRD facility to meet its current liabilities, there can be no assurance that Geoilbent will be able to meet the current ratio requirement on March 31, 2003. As a result of these events Geoilbent's independent accountants have indicated in their report that substantial doubt exists regarding Geoilbent's ability to meet its debts as they come due and continue as a going concern. While no assurance can be given, the Company believes these covenant defaults are temporary and does not result in an other than temporary decline in the Company's investment in Geoilbent or will cause EBRD to declare a default after considering Geoilbent's historical net income, cash flow from operating activities and other matters.

Ability to repay accounts payable. At September 30, 2002, and September 30, 2001, the current liabilities of Geoilbent exceeded its current assets by $35.3 million and $25.0 million, respectively. Included in current liabilities as of September 30, 2002 are loans repayable to EBRD ($22.0 million) and IMB ($0.6 million). The IMB liability was repaid in November 2002. This debt has been classified as current because of Geoilbent's status under the EBRD loan. At December 31, 2002, Geoilbent had accounts payable outstanding of $12.2 million of which approximately $5.9 million was 90 days or more past due. The amounts outstanding were primarily to contractors and vendors for drilling and construction services. Under Russian law, creditors, to whom payments are 90 days or more past due, can force a company into involuntary bankruptcy. We believe most of the significantly overdue payables have now been paid as a result of the $8 million draw down of the EBRD facility.

Ability to repay our loan. As of September 30, 2002, the Geoilbent shareholders had provided Geoilbent with subordinated loans totaling $7.5 million ($2.5 million from Harvest and $5.0 million from Minley). These loans are unsecured and repayable commencing in January 2004. Our interest rate is based on LIBOR up to January 2004, and rises from 8 to 12 percent thereafter. There can be no assurance that Geoilbent will have the ability to repay the loan made by the Company when due.

Ability to maintain or increase production. Because of Geoilbent's significant working capital deficit, a substantial portion of its cash flow must be utilized to reduce accounts and taxes payable. Additionally, in order to maintain or increase proved oil and gas reserves, Geoilbent must make substantial capital expenditures in 2003. Geoilbent's net cash provided by operating activities is dependent on the level of oil prices, which are historically volatile and are significantly impacted by the proportion of production that Geoilbent can sell on the export market. Historically, Geoilbent has supplemented its cash flow from operations with additional borrowings or equity capital. Should oil prices decline for a prolonged period, or if Geoilbent is unable to access the EBRD facility or the shareholders are unwilling to make capital contributions, then Geoilbent would need to reduce its capital expenditures, which could limit its ability to maintain or increase production and, in turn, meet its debt service requirements. Although the Company may consider making a capital contribution, there can be no assurances that the Company will do so, nor can there be any assurances that Geoilbent's other shareholder will be willing or able to do so. Asset sales and financing are restricted under the terms of the EBRD loan.

OUR MINORITY INTEREST IN GEOILBENT MAY LIMIT OUR ABILITY TO INFLUENCE CHANGE. We own 34 percent in Geoilbent. We are reviewing ways to improve operations, such as the secondment of expatriate employees or consultants, the upgrading of drilling equipment, improved operating techniques and economic decision making, but we are a minority partner and therefore may not be able to fully influence changes in the operations.

OUR OPERATIONS IN AREAS OUTSIDE THE U.S. ARE SUBJECT TO VARIOUS RISKS INHERENT IN FOREIGN OPERATIONS, AND OUR STRATEGY TO FOCUS ON VENEZUELA AND RUSSIA LIMITS OUR COUNTRY RISK DIVERSIFICATION. Our operations in areas outside the U.S. are subject to various risks inherent in foreign operations. These risks may include, among other things, loss of revenue, property and equipment as a result of hazards such as expropriation, war, insurrection, civil unrest, strikes and other political risks, increases in taxes and governmental royalties, renegotiation of contracts with governmental entities, changes in laws and policies governing operations of foreign-based companies, currency restrictions and exchange rate fluctuations and other uncertainties arising out of foreign government sovereignty over our international operations. Our international operations may also be adversely affected by laws and policies of the United States affecting foreign trade, taxation and the possibility of having to be subject to exclusive jurisdiction of courts in connection with legal disputes and the possible inability to subject foreign persons to the jurisdiction of the courts in the United States. Our strategy to focus on Venezuela and Russia concentrates our foreign operations risk and increases the potential impact to us of the operating, financial and political risks in those countries.

OUR FOREIGN OPERATIONS EXPOSE US TO FOREIGN CURRENCY RISK. Our principal operations are in Venezuela and Russia which have historically been considered highly inflationary economies. Results of operations in those countries are re-measured in United States dollars, and all currency gains or losses are recorded in the consolidated statement of operations. There are many factors which affect foreign exchange rates and resulting exchange gains and losses, many of which are beyond our influence. We have recognized significant exchange gains and losses in the past, resulting from fluctuations in the relationship of the Venezuelan and Russian currencies to the United States dollar. It is not possible to predict the extent to which we may be affected by future changes in exchange rates. Our Venezuelan receipts are denominated in U.S. dollars, and most expenditures are in U.S. dollars as well. For a discussion of currency controls in Venezuela, see ***Capital Resources and Liquidity*** below.

NEW YORK STOCK EXCHANGE DELISTING. In October 2001, we received a letter from the New York Stock Exchange ("NYSE") notifying us that we had fallen below the continued listing standard of the NYSE. These standards include a total market capitalization of at least $50 million over a 30-day trading period and stockholders' equity of at least $50 million. According to the NYSE's notice, our total market capitalization over the 30 trading days ended October 17, 2001 was $48.2 million and our stockholders' equity was $16.0 million as of September 30, 2001.. In accordance with the NYSE's rules, we submitted a plan to the NYSE detailing how we expected to reestablish compliance with the listing criteria within the next 18 months. In January 2002, the NYSE accepted our business plan, subject to quarterly reviews of the goals and objectives outlined in that plan. By April 2002, the total market capitalization and stockholder's equity deficiencies were eliminated, and as of December 31, 2002, we remained in compliance with NYSE listing standards.

LEVERAGE MATERIALLY AFFECTS OUR OPERATIONS. As of December 31, 2002, our long-term debt was $104.7 million. Our long-term debt represented 38 percent of our debt to total capital at December 31, 2002. Our current cash balances lessen the impact of our debt but it can effect our operations in several important ways, including the following:

- a significant portion of our cash flow from operations is used to pay interest on borrowings;
- the covenants contained in the indentures governing our debt limit our ability to borrow additional funds or to dispose of assets;
- the covenants contained in the indentures governing our debt affect our flexibility in planning for, and reacting to, changes in business conditions;
- the level of debt could impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- the terms of the indentures governing our debt permit our creditors to accelerate payments upon an event of default or a change of control.

OIL PRICE DECLINES AND VOLATILITY COULD ADVERSELY AFFECT OUR REVENUE, CASH FLOWS AND PROFITABILITY. Prices for oil fluctuate widely. The average price we received for oil in Venezuela increased to $13.08 per Bbl for the year ended December 31, 2002, compared to $12.52 per Bbl for the year ended December 31, 2001. Our revenues, profitability and future rate of growth depend substantially upon the prevailing prices of oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to service our debt. In addition, we may have ceiling test writedowns when prices decline. Lower prices may also reduce the amount of oil that we can produce economically. We cannot predict future oil prices. Factors that can cause this fluctuation include:

- relatively minor changes in the supply of and demand for oil;
- market uncertainty;
- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations;
- the price and availability of alternative fuels;
- political and economic conditions in oil-producing countries; and
- overall economic conditions.

LOWER OIL AND NATURAL GAS PRICES MAY CAUSE US TO RECORD CEILING LIMITATION WRITEDOWNS. We use the full cost method of accounting to report our oil and natural gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under full cost accounting rules, the net capitalized costs of oil and gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from proved reserves, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. If net capitalized costs of oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down". This charge does not impact cash flow from operating activities, but does reduce stockholders' equity. The risk that we will be required to write down the carrying value of our oil and gas properties increases when oil and natural gas prices are low or volatile. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. No ceiling test write-downs were required in 2002.

ESTIMATES OF OIL AND NATURAL GAS RESERVES ARE UNCERTAIN AND INHERENTLY IMPRECISE. This Form 10-K contains estimates of our proved oil and natural gas reserves and the estimated future net revenues from such reserves. These estimates are based upon various assumptions, including assumptions required by the Securities and Exchange Commission relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

The process of estimating oil and natural gas reserves is complex. Such process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of reserves set forth. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Actual production, revenue, taxes, development expenditures and operating expenses with respect to our reserves will likely vary from the estimates used. Such variances may be material.

At December 31, 2002, approximately 46 percent of our estimated proved reserves were undeveloped. Undeveloped reserves, by their nature, are less certain. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The estimates of our future reserves include the assumption that we will make significant capital expenditures to develop these reserves. Although we have prepared estimates of our oil and natural gas reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the results will be as estimated. See Supplemental Information on Oil and Natural Gas Producing Activities.

You should not assume that the present value of future net revenues referred to is the current market value of our estimated oil and natural gas reserves. In accordance with Securities and Exchange Commission requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in demand, our ability to produce, or in governmental regulations or taxation will also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of oil and gas properties will affect the timing of actual future net cash flows from estimated proved reserves and their present value. In addition, the 10 percent discount factor, which is required by the Securities and Exchange Commission to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor. The effective interest rate at various times and our risks or the risks associated with the oil and natural gas industry in general will affect the accuracy of the 10 percent discount factor.

WE MAY NOT BE ABLE TO REPLACE PRODUCTION WITH NEW RESERVES. In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful exploration and development activities. Our future oil production is highly dependent upon our level of success in finding or acquiring additional reserves. The business of exploring for, developing or acquiring reserves is capital intensive and uncertain. We may be unable to make the necessary capital investment to maintain or expand our oil and natural gas reserves if cash flow from operations is reduced and external sources of capital become limited or unavailable. We cannot assure you that our future exploration, development and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs.

OUR OPERATIONS ARE SUBJECT TO NUMEROUS RISKS OF OIL AND NATURAL GAS DRILLING AND PRODUCTION ACTIVITIES. Oil and natural gas drilling and production activities are subject to numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be found. The cost of drilling and completing wells is often uncertain. Oil and natural gas drilling and production activities may be shortened, delayed or canceled as a result of a variety of factors, many of which are beyond our control. These factors include:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- weather conditions;
- shortages in experienced labor;
- shortages or delays in the delivery of equipment; and
- delays in receipt of permits or access to lands.

The prevailing price of oil also affects the cost of and the demand for drilling rigs, production equipment and related services. We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our investment. Drilling for oil and natural gas may be unprofitable. Drilling activities can result in dry wells and wells that are productive but do not produce sufficient net revenues after operating and other costs.

THE OIL AND NATURAL GAS INDUSTRY EXPERIENCES NUMEROUS OPERATING RISKS. The oil and natural gas industry experiences numerous operating risks. These operating risks include the risk of fire, explosions, blow-outs, pump and pipe failures, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, natural gas leaks, pipeline ruptures or discharges of toxic gases. If any of these industry operating risks occur, we could have substantial losses. Substantial losses may be caused by injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. The events of September 11, 2001 forced changes to our insurance coverage. Acts of terrorism are "excluded risks" from our property insurance coverage. We cannot assure you that our insurance will be adequate to cover losses or liabilities. We cannot predict the continued availability of insurance at premium levels that justify its purchase.

COMPETITION WITHIN THE INDUSTRY MAY ADVERSELY AFFECT OUR OPERATIONS. We operate in a highly competitive environment. We compete with major and independent oil and natural gas companies for the acquisition of desirable oil and gas properties and the equipment and labor required to develop and operate such properties. Many of these competitors have financial and other resources substantially greater than ours.

OUR OIL AND NATURAL GAS OPERATIONS ARE SUBJECT TO VARIOUS GOVERNMENTAL REGULATIONS THAT MATERIALLY AFFECT OUR OPERATIONS. Our oil and natural gas operations are subject to various foreign governmental regulations. These regulations may be changed in response to economic or political conditions. Matters regulated may include permits for discharges of wastewaters and other substances generated in connection with drilling operations, bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning operations, the spacing of wells, and unitization and pooling of properties and taxation. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve or limit supplies of oil and natural gas, these agencies have restricted the rates of flow of oil and natural gas wells below actual production capacity. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

2002 Financial and Operational Performance

We had two overriding strategic priorities for 2002: (i) to reduce the amount of debt on the balance sheet; and (ii) to improve the value of our producing assets. We also strengthened our management team and recommitted, as a management team and board of directors, to maintain the highest standards in corporate governance, financial transparency and business ethics. In May 2002, the shareholders approved our name change to Harvest Natural Resources, Inc. In September 2002, our board of directors authorized the repurchase of up to one million shares of our common stock. As of March 11, 2003, we have repurchased approximately 80,000 shares for an aggregate price of $0.4 million.

The balance sheet was significantly strengthened by completing the sale of Arctic Gas which produced $220 million in cash and net proceeds, after taxes and expenses, of $190 million (including $30 million for repayment of our intercompany debt) and were used, in part, to redeem all of the $108 million of 11.625 percent senior notes due in May 2003. An additional $20 million of the $105 million of 9.375 percent senior notes due in November 2007 were also retired. The balance of the proceeds were retained to improve our financial flexibility and to be available for acquisitions, reduction of debt or other general corporate purposes. This strategy has already been partially rewarded by our ability to maintain our financial flexibility in spite of the loss of production temporarily as a result of the national civil work stoppage in Venezuela. At December 31, 2002, we had $91.9 million of cash or marketable securities and a debt to total capital ratio of 38 percent compared with over 77 percent at the end of 2001.

We also improved the value of our production, an equally important second priority. We have lowered the cash costs (lease operating, general and administrative) of our produced barrel by 19 percent year-on-year to approximately $5.20 per barrel, increasing unit profitability. We also successfully negotiated a contract to sell 198 Bcf of natural gas to PDVSA over the next 10 years. Establishing a market for this gas allowed us to record an additional 26 net MMBOE of reserves in 2002.

In 2002, Geoilbent, in which we have a 34% interest, was able to improve production. Geoilbent increased production by 33 percent to 7 million barrels per year and has begun restructuring its balance sheet, by converting the loan with EBRD into a $50 million revolving line of credit. Subject to availability, this credit facility will allow Geoilbent to reduce its current liabilities and accelerate the development of the South Tarasovskoye oil field in western Siberia. However, as discussed above under Geoilbent Liquidity, significant issues exist over Geoilbent continuing as a going concern.

2003 Capital Program

Benton-Vinccler's capital expenditures for 2003 are projected to be $45 to $50 million, compared with 2002 capital expenditures of $43 million. To partially fund its capital program, Benton-Vinccler borrowed $15.5 million in October 2002 for the construction of the pipeline and related facilities to deliver gas to PDVSA. Benton-Vinccler has also hedged a portion of its 2003 oil production by purchasing a WTI crude oil "put" to protect part of its 2003 cash flow.

In January 2003, we completed our Tucupita Field development program in Venezuela. In 2003, Benton-Vinccler plans to drill three oil wells in the Bombal Field and construct a pipeline from Bombal to the Tucupita delivery line. Benton-Vinccler also plans to convert two gas injection wells in Uracoa to gas production. Other capital projects relate to the gas project and facilities improvements.

Geoilbent's capital expenditures for 2003 are projected to be approximately $20 million. In 2003, Geoilbent plans to drill up to eighteen wells in South Tarasovskoye and to commence a comprehensive work over program in North Gubkinskoye. An appraisal well is planned in 2003 to delineate a potential south extension of the South Tarasovskoye field that will be developed with further drilling if successful. Geoilbent expects to fund the South Tarasovskoye drilling program through draw downs from the EBRD loan facility. For a description of the EBRD loan agreement and a discussion of Geoilbent's compliance with the covenants and possible liquidity problems, see *Geoilbent's Liquidity* above and *Note 9 - Russian Operations.*

Results of Operations

We include the results of operations of Benton-Vinccler in our consolidated financial statements and reflect the 20 percent ownership interest of Vinccler as a minority interest. We account for our investments in Geoilbent and Arctic Gas using the equity method. We include Geoilbent and Arctic Gas in our consolidated financial statements based on a fiscal year ending September 30. Our results of operations for the year ended December 31, 2002, reflect the results of Geoilbent and Arctic Gas (until sold on April 12, 2002) for the twelve months ended September 30, 2002, 2001 and 2000.

You should read the following discussion of the results of operations for each of the years in the three-year period ended December 31, 2002 and the financial condition as of December 31, 2002 and 2001 in conjunction with our Consolidated Financial Statements and related Notes thereto.

We have presented selected expense items from our consolidated income statement as a percentage of crude oil sales in the following table:

	Years Ended December 31,		
	2002	2001	2000
Operating Expenses	27%	35%	34%
Depletion, Depreciation and Amortization	21	21	12
General and Administrative	13	16	12
Taxes Other Than on Income	3	4	3
Interest	13	20	21

Years ended December 31, 2002 and 2001

Net income for the year ended December 31, 2002 was $100.4 million, or $2.78 per diluted share, compared with $43.2 million for the same period last year. The $100.4 million net income included the after-tax gain from the Arctic Gas Sale of $93.6 million, and the pre-tax $3.3 million, partial recovery of a bad debt related to A. E. Benton (See *Note 13 – Related Party Transactions*); offset, in part, by a pre-tax $13.4 million impairment of the WAB-21 petroleum property located in the South China Sea. Operating and general and administrative expenses were reduced by $12 million, or almost 20 percent compared with 2001.

Our results of operations for the year ended December 31, 2002 primarily reflected the results for Benton-Vinccler in Venezuela, which accounted for all of our production and oil sales revenue. As a result of increases in world crude oil prices, partially offset by lower production from the South Monagas Unit, oil sales in Venezuela were 3.8 percent higher in 2002 compared with 2001. Realized fees per barrel increased 4.5 percent (from $12.52 in 2001 to $13.08 in 2002).

Our revenues increased $4.6 million, or 3.6 percent, during the year ended December 31, 2002, compared with 2001. This was due to increased oil sales revenue in Venezuela as a result of increases in world crude oil prices, partially offset by lower sales quantities. Our sales quantities for the year ended December 31, 2002 from Venezuela were 9.7 MMBbls compared to 9.8 MMBbls for the year ended December 31, 2001. The decrease in sales quantities of 100,000 Bbls, or less than 1 percent, was due primarily to logistics and equipment delays in early 2002 at the Tucupita field and the national civil work stoppage which led to the shut-in of our production in late December 2002 for nine days. Average production for the year decreased by less than 775 Bbls per day for the aforementioned reasons.

Our operating expenses decreased $8.8 million, or 21 percent, for the year ended December 31, 2002, compared with the year ended December 31, 2001. Lower fuel gas, water and oil treatments accounted for $3.4 million of the reduction. Reduced workover expense ($2.6 million) and lower expenses associated with the transportation of Tucupita oil ($5.0 million) with the completion of the Tucupita oil pipeline in late 2001 were offset by $1.1 million of increases in various other categories. Depletion, depreciation and amortization increased $0.8 million, or 4 percent, during the year ended December 31, 2002, compared with 2001 primarily due to the first three quarters of 2002 having been calculated on the lower beginning of the year reserves. We added 198 Bcf or 33 MMBOE in the fourth quarter which will impact this calculation prospectively. Depletion expense per barrel of oil produced from Venezuela during 2002 was $2.57 compared with $2.26 during 2001 primarily due to future development costs. We recognized write-downs of capitalized costs of $13.4 million associated with WAB-21 offshore China and $1.1 million for the Lakeside Prospect exploration activities during the year ended December 31, 2002, compared with $0.5 million associated with final costs associated with prior exploration activities. General and administrative expenses decreased $3.6 million from 2001 to 2002. The move to Houston was completed in 2001 and overall staff levels were reduced to the current level of ten in Houston. We recognized $3.3 million of income for the partial recovery of prior year bad debt allowance for the funds received from the A.E. Benton bankruptcy. The consideration includes 600,000 shares of stock taken into treasury at a price of $3.56 per share and approximately $1.1 million in cash.

Taxes other than on income decreased $1.3 million, or 24 percent, during the year ended December 31, 2002, compared with 2001. This was primarily due to decreased Venezuelan municipal taxes and a one-time adjustment of U.S. employment taxes of $0.7 million.

Investment income and other decreased $1.0 million, or 33 percent, during the year ended December 31, 2002, compared with 2001. This was due to lower interest rates earned on average cash and marketable securities balances. Interest expense decreased $8.6 million, or 34 percent, during the year ended December 31, 2002, compared with 2001. We redeemed all $105 million of our 11.625 percent Senior Notes due in May 2003 and purchased $20 million face of the 9.375 percent Senior Notes due in November 2007. In October 2002, we borrowed under a $15.5 million loan to finance the construction of the gas pipeline in Venezuela from the Uracoa field to the PDVSA sales line.

Net gain on exchange rates increased $3.8 million, or 493 percent for the year ended December 31, 2002, compared with 2001. This was due to the significant devaluation of the Bolivar. We realized income before income taxes and minority interest of $169.8 million during the year ended December 31, 2002, compared with $7.2 million in 2001. The increase was dominated by the Arctic Gas Sale. The 2001 income tax benefit related to the potential utilization by the Arctic Gas Sale of net operating loss carry forwards in 2002. The effective tax rate of 36 percent reflects the approximate rate for Venezuela and no tax benefits are being recognized for expenses incurred in the U.S. The income attributable to the minority interest increased $3.8 million for the year ended December 31, 2002, compared with 2001. This was primarily due to the increased profitability (oil prices) and reduced expenses of Benton-Vinccler.

Equity in net earnings of affiliated companies decreased $5.7 million, during the year ended December 31, 2002, compared with 2001. This was primarily due to the decreased income from Geoilbent and the elimination of Arctic Gas equity income on April 12, 2002, the date of its sale. Geoilbent's equity income declined from $7.0 million in 2001 to $1.6 million in 2002. We recorded equity in net losses of Arctic Gas in both years. Revenues from Geoilbent were $31.0 million for the year ended September 30, 2002, compared with $34.4 million for 2001. The decrease of $3.3 million, or 10 percent, was due to lower Russian domestic crude oil prices offset by higher sales quantities. Prices for Geoilbent's export crude oil averaged $21.73 per Bbl and its domestic crude oil averaged $8.89 during the year ended September 30, 2002, compared with $20.48 per Bbl for export crude oil and $13.69 for domestic for the year ended September 30, 2001. Our share of Geoilbent oil sales quantities increased by 587,102 Bbls, or 33 percent, from 1,762,814 Bbls sold during the year ended September 30, 2001, to 2,349,916 Bbls sold during the year ended September 30, 2002.

Years ended December 31, 2001 and 2000

Our results of operations for the year ended December 31, 2001 primarily reflected the reversal of our tax valuation allowance and results for Benton-Vinccler in Venezuela, which accounted for all of our production and oil sales revenue. As a result of decreases in world crude oil prices, partially offset by higher production from the South Monagas Unit, oil sales in Venezuela were 13 percent lower in 2001 compared with 2000. Realized fees per barrel decreased 16 percent (from $14.94 in 2000 to $12.52 in 2001) and oil sales quantities increased 4 percent (from 9.4 MMBbls of oil in 2000 to 9.8 MMBbls of oil in 2001). Our operating expenses from the South Monagas Unit decreased by 14 percent due to decreased workover costs and completion of the 31-mile oil pipeline in the fourth quarter of 2001 to transport oil from the Tucupita field to the central processing unit in the Uracoa field.

Our revenues decreased $17.9 million, or 13 percent, during the year ended December 31, 2001 compared with 2000. This was due to decreased oil sales revenue in Venezuela as a result of decreases in world crude oil prices, partially offset by higher sales quantities. Our sales quantities for the year ended December 31, 2001 from Venezuela were 9.8 MMBbls compared to 9.4 MMBbls for the year ended December 31, 2000. The increase in sales quantities of 413,428 Bbls, or 4 percent, was due primarily to production efficiency and reservoir management at Uracoa, and enhanced drilling performance for the eight wells drilled in the Uracoa field beginning August 31, 2001 as a result of incorporating information from the field simulation study conducted during the first eight months of 2001. Production increased to 28,000 Bbls or oil per day by the end of 2001 as a result of drilling 8 additional wells during the year. Prices for crude oil averaged $12.52 per Bbl (pursuant to terms of an operating service agreement) from Venezuela compared with $14.94 per Bbl for 2000.

Our operating expenses decreased $4.7 million, or 10 percent, which included a fuel gas charge of $3.2 million, during the year ended December 31, 2001 compared to the year ended December 31, 2000. The fuel gas charge related to a dispute regarding a difference between rates we paid and rates claimed by PDVSA for natural gas used as fuel for the period 1997 through 2000. Depletion, depreciation and amortization increased $8.3 million, or 48 percent, during the year ended December 31, 2001 compared with 2000 primarily due to decreased proved reserves. Depletion expense per barrel of oil produced from Venezuela during 2001 was $2.26 compared with $1.68 during 2000 as a result of a decrease in proved reserves. We recognized write-downs of capitalized costs of $0.5 million associated with exploration activities during the year ended December 31, 2001 compared with $1.3 million associated with exploration activities in California. General and administrative expenses decreased $2.3 million from $16.7 million in 2000 to $14.4 million in 2001, exclusive of $5.7 million of non-recurring costs. Non-recurring general and administrative costs are comprised of $2.3 million in debt exchange cost, $1.1 million in California lease relinquishment, $0.2 million relocation costs to Houston and $2.1 million severance and termination payments paid or accrued in 2001.

Taxes other than on income increased $1.0 million, or 22 percent, during the year ended December 31, 2001 compared with 2000. This was primarily due to increased Venezuelan municipal taxes.

Investment income and other decreased $5.5 million, or 64 percent, during the year ended December 31, 2001 compared with 2000. This was due to lower average cash and marketable securities balances. Interest expense decreased $4.1 million, or 14 percent, during the year ended December 31, 2001 compared with 2000. This was primarily due to the reduction of debt balances, partially offset by a reduction of capitalized interest expense. Net gain on exchange rates increased $0.4 million, or 136 percent for the year ended December 31, 2001 compared with 2000. This was due to changes in the value of the Bolivar. We realized income before income taxes and minority interest of $7.2 million during the year ended December 31, 2001 compared with $33.1 million in 2000. The negative effective tax rate varies from the U.S. statutory rate of 35 percent primarily because of the reversal of a U.S. tax valuation allowance. The reversal related to the potential utilization of net operating loss carry forwards. We have determined that it is more likely than not that these U.S. deferred tax assets will be realized in 2002. The income attributable to the minority interest decreased $2.3 million for the year ended December 31, 2001 compared with 2000. This was primarily due to the decreased profitability (oil prices) of Benton-Vinccler.

Equity in net earnings of affiliated companies increased $0.6 million, or 11 percent, during the year ended December 31, 2001 compared with 2000. This was primarily due to the increased income from Geoilbent. Our share of revenues from Geoilbent was $34.4 million for the year ended September 30, 2001 compared with revenues of $26.8 million for 2000. The increase of $7.6 million, or 27 percent, was due to higher world crude oil prices and higher sales quantities. Prices for Geoilbent's crude oil averaged $19.51 per Bbl during the year ended September 30, 2001 compared with $18.54 per Bbl for the year ended September 30, 2000. Our share of Geoilbent oil sales quantities increased by 318,633 Bbls, or 22 percent, from 1,444,181 Bbls sold during the year ended September 30, 2000 to 1,762,814 Bbls sold during the year ended September 30, 2001.

Capital Resources and Liquidity

The oil and natural gas industry is a highly capital intensive and cyclical business with unique operating and financial risks (see Risk Factors). We require capital principally to service our debt and to fund the following costs:

- drilling and completion costs of wells and the cost of production, treating and transportation facilities;
- geological, geophysical and seismic costs; and
- acquisition of interests in oil and gas properties.

The amount of available capital will affect the scope of our operations and the rate of our growth. Our future rate of growth also depends substantially upon the prevailing prices of oil. Prices also affect the amount of cash flow available for capital expenditures and our ability to service our debt. In 2002, Benton-Vinccler instituted a hedging program to establish a crude oil price floor using a WTI costless collar for our Tucupita development drilling program. Benton-Vinccler has also hedged a portion of its 2003 oil sales by purchasing a WTI crude oil "put" to protect its 2003 cash flow. The put is for 10,000 barrels of oil per day for the period of March 1, 2003 through December 31, 2003. Due to the pricing structure for our Venezuela oil, the put has the economic effect of hedging approximately 20,000 Bopd. The put costing $2.50 per barrel, or approximately $7.7 million, has a strike price of $30.00 per barrel.

In February 2002, the Venezuelan Bolivar was allowed to float against the U.S. dollar. On February 5, 2003, the Venezuelan government imposed currency controls and created the Commission for Administration of Foreign Currency ("CADIVI") with the task of establishing the detailed rules and regulations and generally administering the exchange control regime. The currency controls fix the exchange rate between the Bolivar and the U.S. dollar, and restricts the ability to exchange Bolivars for dollars and vice versa. Oil companies, such as Benton-Vinccler are allowed to receive payments for oil sales in U.S. currency and pay dollar-denominated expenses from those payments. We are unable to predict the full impact of the currency controls on us or Benton-Vinccler as the CADIVI has not issued final regulations. The near-term effect has been to restrict Benton-Vinccler's ability to make payments to employees and vendors in Bolivars, causing it to borrow money on a short-term basis to meet these obligations. All of these short-term borrowings have been repaid and while we now have Bolivars to meet our current obligations, the situation could change. In addition, the currency controls have increased the cost of Benton-Vinccler's Bolivar denominated debt. Benton-Vinccler has provided the thirty day notice of its intention to repay its Bolivar denominated debt. The full amount will be repaid on March 31, 2003. As of February 24, 2003, we have cash reserves of approximately $75 million and do not expect the currency conversion restriction to adversely affect our ability to meet our short-term loan obligations.

Our ability to pay interest on our debt and general corporate overhead is dependent upon the ability of Benton-Vinccler to make loan repayments, dividends and other cash payments to us. However, there have been, and may again be, unforeseeable interruptions in oil and gas sales or there may be contractual obligations or legal impediments such as the recently instituted currency controls to receiving dividends or distributions from Benton-Vinccler, which could prohibit Benton-Vinccler from remitting funds to us. Management does not believe that the currency controls will prohibit our ability to receive funds from Benton-Vinccler, although were it to do so, our ability to meet our cash requirements would be adversely affected.

Debt Reduction. We currently have a significant debt principal obligation payable in 2007 ($85 million). We intend to continue to evaluate open market debt purchases of the obligations due in 2007 to further reduce debt. In 2001 Benton-Vinccler borrowed $12.3 million from a Venezuelan commercial bank for the construction of a Tucupita to Uracoa oil pipeline. Benton-Vinccler has provided the thirty day notice of its intention to repay its Bolivar denominated debt. The full amount will be repaid on March 31, 2003. As of February 24, 2003, we have cash reserves of approximately $75 million and do not expect the currency conversion restriction to adversely affect our ability to meet our short-term loan obligations.

Working Capital. Our capital resources and liquidity are affected by the timing of our semiannual interest payments of approximately $4.0 million each May 1 and November 1 on the 9.375 percent Senior Notes due in November 2007 and by receipt of the quarterly payments from PDVSA at the end of the months of February, May, August and November pursuant to the terms of the contract between Benton-Vinccler and PDVSA regarding the South Monagas Unit. As a consequence of the timing of these interest payment outflows and the PDVSA payment inflows, our cash balances can increase and decrease dramatically on a few dates during the year. In each May and November in particular, interest payments at the beginning of the month and PDVSA payments at the end of the month create large swings in our cash balances. At December 31, 2002, we had $91.9 million of cash or cash equivalents.

Benton-Vinccler's oil and gas pipeline project loans allow the lender to accelerate repayment if production ceases for a period greater than thirty days. During the production shut-in which started in December 2002, Benton-Vinccler was granted a waiver of this provision until February 18, 2003 for a prepayment of the next two principal obligations aggregating $0.9 million. This prepayment, while using cash reserves, reduces our net interest expense as the current interest expense was more than the current interest income earned on the invested funds. On February 8, 2003, Benton-Vinccler commenced production, thereby eliminating the need for an additional waiver. A future disruption of production could trigger the debt acceleration provision again. While no assurances can be given, we believe Benton-Vinccler would be able to obtain another waiver.

The net funds raised and/or used in each of the operating, investing and financing activities are summarized in the following table and discussed in further detail below:

	Year Ended December 31, (in thousands) 2002	2001	2000
Net cash provided by operating activities	$ 42,627	$ 36,608	$ 51,763
Net cash provided by (used in) investing activities	126,492	(48,012)	(28,772)
Net cash provided by (used in) financing activities	(113,642)	5,296	(29,006)
Net increase (decrease) in cash	$ 55,477	$ (6,108)	$ (6,015)

At December 31, 2002, we had current assets of $132.0 million and current liabilities of $35.0 million, resulting in working capital of $97.0 million and a current ratio of 3.8:1. This compares with a negative working capital of $0.6 million and a negative current ratio at December 31, 2001. The increase in working capital of $97.6 million was primarily due to higher oil prices and the Arctic Gas Sale.

Cash Flow from Operating Activities. During the years ended December 31, 2002 and 2001, net cash provided by operating activities was approximately $42.6 million and $36.6 million, respectively. The $6.0 million increase was primarily due to higher oil revenues and lower operating expenses.

Cash Flow from Investing Activities. During the year ended December 31, 2002 and 2001, we had drilling and production-related capital expenditures of approximately $43.3 million and $43.4 million, respectively. Of the 2002 expenditures, $42.5 million was attributable to the development of the South Monagas Unit and $0.8 million was attributable to Lakeside Exploration Prospect.

The timing and size of capital expenditures for the South Monagas Unit are entirely at our discretion. We anticipate that Geoilbent will continue to fund its expenditures through its own cash flow and credit facilities. Our remaining capital commitments worldwide are relatively minimal and are substantially at our discretion. We will also be required to make annual interest payments of approximately $8.0 million on the 2007 Notes.

We continue to assess production levels and commodity prices in conjunction with our capital resources and liquidity requirements. Benton-Vinccler entered into a commodity contract (costless collar) in 2002 and, as described above, a WTI crude oil "put" for a portion of 2003.

Cash Flow from Financing Activities. In November 1997, we issued $115 million in 9.375 percent senior unsecured notes due November 1, 2007, of which we subsequently repurchased $30 million at their par value for cash. Interest on these notes is due May 1st and November 1st of each year. The indenture agreements provide for certain limitations on liens, additional indebtedness, certain investment and capital expenditures, dividends, mergers and sales of assets. At December 31, 2002, we were in compliance with all covenants of the indenture.

We have an approximately $11,000 lease obligation per month for our Houston office space. This lease is valid through August 2004. The following table summarizes our contractual obligations at December 31, 2002.

Contractual Obligation	Payments (in thousands) Due by Period: Total	Less than 1 Year	1-2 Years	3-4 Years	After 4 Years
Long Term Debt	$ 106,567	$ 1,867	$ 7,035	$ 7,035	$ 90,630
Building Lease	264	132	132	—	—
Total	$ 106,831	$ 1,999	$ 7,167	$ 7,035	$ 90,630

While we can give no assurance, we currently believe that our cash flow from operations coupled with our cash and marketable securities on hand will provide sufficient capital resources and liquidity to fund our planned capital expenditures, investments in and advances to affiliates, and semiannual interest payment obligations for the next

12 months. Our expectation is based upon our current estimate of projected prices, the purchase of a WTI crude oil "put" (discussed above) and production levels, and our assumptions that there will be no further disruptions to our production and that PDVSA will timely pay our invoices. Actual results could be materially affected if there is a significant change in our expectations or assumptions. Future cash flows are subject to a number of variables including, but not limited to, the level of production and prices, as well as various economic and political conditions that have historically affected the oil and natural gas business. Additionally, prices for oil are subject to fluctuations in response to changes in supply, market uncertainty and a variety of factors beyond our control.

We currently have a significant debt obligation of $85 million payable in November 2007. Our ability to meet our debt obligation and to reduce our level of debt depends on the successful implementation of our strategic objectives.

Effects of Changing Prices, Foreign Exchange Rates and Inflation

Our results of operations and cash flow are affected by changing oil prices. Fluctuations in oil and natural gas prices may affect our total planned development activities and capital expenditure program.

There are presently no restrictions in Russia that restrict converting U.S. dollars into local currency or local currency into U.S. dollars for routine business operations, such as the payments of invoices, and debt obligations within the Russian Federation. As noted above under ***Capital Resources and Liquidity,*** Venezuela imposed currency exchange restrictions on February 5, 2003. We are unable to predict the impact of the currency controls on us or Benton-Vinccler as the Government has not issued final regulations.

Within the United States, inflation has had a minimal effect on us, but it is potentially an important factor in results of operations in Venezuela and Russia. With respect to Benton-Vinccler and Geoilbent, a significant majority of the sources of funds, including the proceeds from oil sales, our contributions and credit financings, are denominated in U.S. dollars, while local transactions in Russia and Venezuela are conducted in local currency. If the rate of increase in the value of the dollar compared with the Bolivar continues to be less than the rate of inflation in Venezuela, then inflation could be expected to have an adverse effect on Benton-Vinccler.

During the year ended December 31, 2002, our net foreign exchange gain attributable to our international operations was $4.6 million. However, there are many factors affecting foreign exchange rates and resulting exchange gains and losses, many of which are beyond our control. We have recognized significant exchange gains and losses in the past, resulting from fluctuations in the relationship of the Venezuelan and Russian currencies to the U.S. dollar. It is not possible for us to predict the extent to which we may be affected by future changes in exchange rates and exchange controls.

Critical Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts of all wholly-owned and majority-owned subsidiaries. The equity method of accounting is used for companies and other investments in which we have significant influence. All intercompany profits, transactions and balances have been eliminated. We account for our investment in Geoilbent and Arctic Gas based on a fiscal year ending September 30.

Oil and natural gas revenue is accrued monthly based on sales. Each quarter, Benton-Vinccler invoices PDVSA based on barrels of oil accepted by PDVSA during the quarter, using quarterly adjusted U.S. dollar contract service fees per barrel.

Property and Equipment

We follow the full cost method of accounting for oil and gas properties with costs accumulated in cost centers on a country-by-country basis. All costs associated with the acquisition, exploration, and development of oil and natural gas reserves are capitalized as incurred, including exploration overhead. Only overhead that is directly identified with acquisition, exploration or development activities is capitalized. All costs related to production, general corporate overhead and similar activities are expensed as incurred. The costs of unproved properties are excluded from amortization until the properties are evaluated. We regularly evaluate our unproved properties on a country-by-country basis for possible impairment. If we abandon all exploration efforts in a country where no proved reserves are assigned, all exploration and acquisition costs associated with the country are expensed. Due to the unpredictable nature of exploration drilling activities, the amount and timing of impairment expenses are difficult to predict with any certainty.

The full cost method of accounting uses proved reserves in the calculation of depletion, depreciation and amortization. Proved reserves are estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those which are expected to be recovered through existing wells with existing equipment and operating methods. Proved reserves cannot be measured exactly, and the estimation of reserves involves judgmental determinations. Reserve estimates must be reviewed and adjusted periodically to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes. The estimates are based on current technology and economic conditions, and we consider such estimates to be reasonable and consistent with current knowledge of the characteristics and extent of production. The estimates include only those amounts considered to be Proved Reserves and do not include additional amounts which may result from new discoveries in the future, or from application of secondary and tertiary recovery processes where facilities are not in place or for which transportation and/or marketing contracts are not in place. Changes in previous estimates of proved reserves result from new information obtained from production history and changes in economic factors. A large portion of our proved reserves base from consolidated operations is comprised of oil and gas properties that are sensitive to oil price volatility. We are susceptible to significant upward and downward revisions to our proved reserve volumes and values as a result of changes in year end oil and gas prices and the corresponding adjustment to the projected economic life of such properties. Prices for oil and gas are likely to continue to be volatile, resulting in future revision to our proved reserve base. We perform a quarterly cost center ceiling test of our oil and gas properties under the full cost accounting rules of the Securities and Exchange Commission. These rules generally require that we price our future oil and gas production at the oil and gas prices in effect at the end of each fiscal quarter and require a write-down if our capitalized costs exceed this "ceiling," even if prices declined for only a short period of time. We have had no write-downs due to these ceiling test limitations since 1998. Given the volatility of oil and gas prices, it is likely that our estimate of discounted future net revenues from proved oil and gas reserves will change in the near term. If oil and gas prices decline significantly in the future, even if only for a short period of time, write-downs of our oil and gas properties could occur. Write-downs required by these rules do not directly impact our cash flows from operating activities.

Income Taxes

Deferred income taxes reflect the net tax effects, calculated at currently enacted rates, of (a) future deductible/taxable amounts attributable to events that have been recognized on a cumulative basis in the financial statements or income tax returns, and (b) operating loss and tax credit carry forwards. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Foreign Currency

We have significant operations outside of the United States, principally in Venezuela and an equity investment in Russia. Amounts denominated in non-U.S. currencies are re-measured in United States dollars, and all currency gains or losses are recorded in the statement of income. We attempt to manage our operations in a manner to reduce our exposure to foreign exchange losses. However, there are many factors that affect foreign exchange rates and resulting exchange gains and losses, many of which are beyond our influence. We have recognized significant exchange gains and losses in the past, resulting from fluctuations in the relationship of the Venezuelan and Russian currencies to the United States dollar. It is not possible to predict the extent to which we may be affected by future changes in exchange rates.

New Accounting Pronouncements

In September 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost should be allocated to expense using a systematic and rational method. SFAS No. 143 is effective for fiscal years beginning after September 15, 2002. We will adopt SFAS No. 143 effective January 1, 2003, and such adoption will not materially impact the financial statements since our PDVSA operating service agreement provides that all wells revert to PDVSA at contract expiration and intervening abandonment obligations are minor. Further we believe the adoption of SFAS No. 143 by Geoilbent will not materially impact our equity in earnings given that the fair value of such obligations are not material as of September 30, 2002.

In May 2002, the FASB issued SFAS No. 145, Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections". SFAS 145 rescinds the automatic treatment of gains or losses from extinguishment of debt as extraordinary items as outlined in APB Opinion No. 30, "Reporting the Results of Operations, Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions". As allowed under the provisions of SFAS 145, we had decided to adopt SFAS 145 early. Accordingly, all gains on early extinguishment of debt have been reclassified to other non-operating income in the accompanying consolidated financial statements.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activity. SFAS 146 replaces Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)". The provisions of this statement shall be effective for exit or disposal activities initiated after December 31, 2002. The Company will account for exit or disposal activities initiated after December 31, 2002, in accordance with the provisions of SFAS No. 146.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure an amendment of FASB Statement No. 123". The standard amends SFAS Statement No. 123 that provides alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The Company intends to adopt the "Prospective method" which will apply the recognition provisions to all employee awards granted, modified, or settled in 2003.

The weighted average fair value of the stock options granted from our stock option plans during 2002, 2001 and 2000 was $4.84, $1.33 and $1.65, respectively. The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used:

	2002	2001	2000
Expected life	10.0 years	10.0 years	9.1 years
Risk-free interest rate	5.0%	5.1%	6.1%
Volatility	74%	72%	74%
Dividend Yield	0%	0%	0%

We accounted for stock-based compensation in accordance with Accounting Principles Board Opinion No. 25 and related interpretations, under which no compensation cost has been recognized for stock option awards. Had compensation cost for the plans been determined consistent with SFAS 123, our pro forma net income and earnings per share for 2002, 2001 and 2000 would have been as follows (in thousands, except per share data):

	2002	2001	2000
Net income as reported	$100,362	$ 43,237	$ 20,488
Add: Stock-based employee compensation expense included in reported net income due to acceleration of vesting of former employees	915	35	110
Deduct: Total stock-based employee compensation expense determined under fair value based method for all grants awarded since January 1, 1995	(2,905)	(2,459)	(4,374)
Net income	$ 98,372	$ 40,813	$ 16,224
Net income per common share:			
Basic	$ 2.87	$ 1.20	$ 0.53
Diluted	$ 2.75	$ 1.20	$ 0.53

In November 2002 FASB interpretation, or FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantee of Indebtedness of Others" was issued. FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of FIN 45. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. As of December 31, 2002, the Company does not have any guarantor obligations.

In January 2003 FASB Interpretation 46, or FIN 46, "Consolidation of Variable Interest Entities" was issued. FIN 46 identifies certain off-balance sheet arrangements that meet the definition of a variable interest entity (VIE). The primary beneficiary of a VIE is the party that is exposed to the majority of the risks and/or returns of the VIE. In future accounting periods, the primary beneficiary will be required to consolidate the VIE. In addition, more extensive disclosure requirements apply to the primary beneficiary, as well as other significant investors. We do not believe we participate in any arrangement that would be subject to the provisions of FIN 46.

In November 2002, the International Practices Task Force concluded that Russia has ceased being a highly inflationary economy as of January 1, 2003. As a result of the Task Force conclusion, companies reporting under US GAAP in Russia will be required to apply the guidance contained in Emerging Issues Task Force ("EITF") No. 92-4 and EITF No. 92-8 as of January 1, 2003. We have not yet estimated the effect that EITF No. 92-4 and EITF No. 92-8 will have on Geoilbent or our equity position.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk from adverse changes in oil and natural gas prices, interest rates, foreign exchange and political risk, as discussed below.

Oil Prices

As an independent oil producer, our revenue, other income and equity earnings and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of crude oil and natural gas. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control. Historically, prices received for oil production have been volatile and unpredictable, and such volatility is expected to continue. Through February 14, 2003, we utilized a costless collar hedge transaction with respect to a portion of our oil production to achieve a more predictable cash flow, establish an acceptable rate of return on our Tucupita drilling program, as well as to reduce our exposure to price fluctuations. Benton-Vinccler has hedged a portion of its 2003 oil production by purchasing a WTI crude oil "put" to protect its 2003 cash flow. Because gains or losses associated with hedging transactions are included in oil sales when the hedged production is delivered, such gains and losses are generally offset by similar changes in the realized prices of the commodities. See Note 1 – Derivatives and Hedging for a complete discussion of our derivative activity.

Interest Rates

Total long-term debt at December 31, 2002 of $104.7 million consisted of fixed-rate senior unsecured notes maturing in 2007 ($85.0 million). Benton-Vinccler has $18.2 million U.S. Dollar denominated and 1.5 million Bolivar denominated variable rate loans. A hypothetical 10 percent adverse change in the interest rate would not have had a material affect on our results of operations.

Foreign Exchange

For the Venezuelan operations, oil and gas sales are received under a contract in effect through 2012 in U.S. dollars; expenditures are both in U.S. dollars and local currency. For Geoilbent, a majority of the oil sales are received in Rubles; expenditures are both in U.S. dollars and local currency, although a larger percentage of the expenditures are in local currency. We have utilized no currency hedging programs to mitigate any risks associated with operations in these countries, and therefore our financial results are subject to favorable or unfavorable fluctuations in exchange rates and inflation in these countries. Venezuela has recently imposed currency exchange controls (see Capital Resources and Liquidity above).

Political Risk

The stability of government in Venezuela and the government's relationship with the state-owned national oil company, PDVSA, remain significant risks for our company. PDVSA is the sole purchaser of all Venezuelan oil and gas production. In April 2002 there was a failed attempt to remove the President of Venezuela. During this period, sales were curtailed but our oil production was not interrupted, but it did delay the importation of critical equipment, which contributed to the slowdown in our drilling operations. From December 14, 2002 through February 6, 2003, no sales were made because of PDVSA's inability to accept our oil due to the national civil work stoppage. As a result, 2002 sales were reduced by approximately 550,000 barrels and sales in 2003 were reduced by an estimated 1.2 million barrels. While the situation has stabilized and production is returning to normal, there continues to be political and economic uncertainty that could lead to another disruption of our sales. As a result of the national civil work stoppage, the Government of Venezuela terminated several thousand PDVSA employees and announced a decentralization of PDVSA's operations. While the effect of these changes cannot be predicted, it could adversely affect PDVSA's ability to manage its contracts and meet its obligations with its suppliers and vendors, such as Benton-Vinccler. As a result of the situation in PDVSA, its payment to Benton-Vinccler for crude delivered in the fourth quarter 2002 was late by seven days. We believe that the payment demonstrates PDVSA's commitment to building its production levels back to full capacity and returning to more normalized business relations with its customers and suppliers. While we have substantial cash reserves to withstand a future disruption, a prolonged loss of sales or a failure or delay by PDVSA to pay our invoices could have a material adverse effect on our financial condition.

Item 8. Financial Statements and Supplementary Data

The information required by this item is included herein on pages S-1 through S-37.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

PART III

Item 10. Directors and Executive Officers of the Registrant*

Item 11. Executive Compensation*

Item 12. Security Ownership of Certain Beneficial Owners and Management*

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a) (c)
Equity compensation plans approved by security holders	4,244,463	$8.68	310,000
Equity compensation plans not approved by security holders[1]	1,170,650	2.92	—
Total	5,415,113	$7.43	310,000

(1) See Note 6 of Notes to Consolidated Financial Statements for a description of options issued to individuals other than officers, directors or employees of the Company. The 1999 Stock Option Plan permits the granting of stock options to purchase up to 2,500,000 shares of our common stock in the form of ISOs, NQSOs or a combination of each, with exercise prices not less than the fair market value of the common stock on the date of the grant, subject to the dollar limitations imposed by the Internal Revenue Code. In the event of a change in control of our company, all outstanding options become immediately exercisable to the extent permitted by the plan. Options granted to employees under the 1999 Stock Option Plan vest 50 percent after the first year and 25 percent after each of the following two years, or they vest ratably over a three-year period, from their dates of grant and expire ten years from grant date or three months after retirement, if earlier. All options granted to outside directors and consultants under the 1999 Stock Option Plan vest ratably over a three-year period from their dates of grant and expire ten years from grant date. These were the only compensation plans in effect that were adopted without the approval of the Company's stockholders.

Item 13. Certain Relationships and Related Transactions*

* Reference is made to information under the captions "Election of Directors", "Executive Officers", "Executive Compensation", "Stock Ownership", and "Certain Relationships and Related Transactions" in our Proxy Statement for the 2003 Annual Meeting of Shareholders.

Item 14. Controls and Procedures

In its recent Release No. 34-46427, effective August 29, 2002, the SEC, among other things, adopted rules requiring reporting companies to maintain disclosure controls and procedures to provide reasonable assurance that a registrant is able to record, process, summarize and report the information required in the registrant's quarterly and annual reports under the Securities Exchange Act of 1934 (the "Exchange Act"). While we believe that our existing disclosure controls and procedures have been effective to accomplish these objectives, we intend to continue to examine, refine and formalize our disclosure controls and procedures and to monitor ongoing developments in this area.

Our principal executive officer and our principal financial officer have informed us that, based upon their evaluation as of December 31, 2002, of our disclosure controls and procedures (as defined in Rule 13a-14(c) and Rule 15d-14(c) under the Exchange Act), they have concluded that those disclosure controls and procedures are effective.

There have been no changes in our internal controls or in other factors known to us that could significantly affect these controls subsequent to their evaluation, nor any corrective actions with regard to significant deficiencies and material weaknesses.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

2. Consolidated Financial Statement Schedules:

Schedule II – Valuation and Qualifying Accounts

Schedule III – Financial Statements and Notes for LLC Geoilbent

All other schedules are omitted because they are not applicable or the required information is shown in the financial statements or the notes thereto.

3. Exhibits:

3.1 Certificate of Incorporation filed September 9, 1988 (Incorporated by reference to Exhibit 3.1 to our Registration Statement (Registration No. 33-26333)).

3.2 Amendment to Certificate of Incorporation filed June 7, 1991 (Previously filed as an exhibit to our S-1 Registration Statement (Registration No. 33-39214)).

3.3 Restated Bylaws (Incorporated by reference to Exhibit 3.3 to our Form 10-Q, filed August 13, 2001).

4.1 Form of Common Stock Certificate (Previously filed as an exhibit to our S-1 Registration Statement (Registration No. 33-26333)).

4.2 Certificate of Designation, Rights and Preferences of the Series B. Preferred Stock of Benton Oil and Gas Company, filed May 12, 1995. (Previously filed as an Exhibit 4.1 to our Form 10-Q filed on May 13, 2002, File No. 1-10762.)

4.3 Rights Agreement between Benton Oil and Gas Company and First Interstate Bank, Rights Agent dated April 28, 1995. (Previously filed as Exhibit 4.1 to our Form 10-Q filed on August 13, 2002, File No. 1-10762.)

10.1 Form of Employment Agreements (Exhibit 10.19) (Previously filed as an exhibit to our S-1 Registration Statement (Registration No. 33-26333)).

10.2 Agreement dated October 16, 1991 among Benton Oil and Gas Company, Puror State Geological Enterprises for Survey, Exploration, Production and Refining of Oil and Gas; and Puror Oil and Gas Production Association (Exhibit 10.14) (Previously filed as an exhibit to our S-1 Registration Statement (Registration No. 33-46077)).

10.3 Operating Service Agreement between Benton Oil and Gas Company and Lagoven, S.A., which has been subsequently combined into PDVSA Petroleo y Gas, S.A., dated July 31, 1992, (portions have been omitted pursuant to Rule 406 promulgated under the Securities Act of 1933 and filed separately with the Securities and Exchange Commission--Exhibit 10.25) (Previously filed as an exhibit to our S-1 Registration Statement (Registration No. 33-52436)).

10.4 Indenture dated November 1, 1997 between Benton Oil and Gas Company and First Trust of New York, National Association, Trustee related to an aggregate of $115,000,000 principal amount of 9 3/8 percent Senior Notes due 2007. (Incorporated by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended September 30, 1997, File No. 1-10762.)

10.5 Note payable agreement dated March 8, 2001 between Benton-Vinccler, C.A. and Banco Mercantil, C.A. related to a note in the principal amount of $6,000,000 with interest at LIBOR plus five percent, for financing of Tucupita Pipeline (Incorporated by reference to Exhibit 10.24 to our Form 10-Q, filed on May 15, 2001, File No. 1-10762).

10.6 Note payable agreement dated March 8, 2001 between Benton-Vinccler, C.A. and Banco Mercantil, C.A. related to a note in the principal amount of 4,435,200,000 Venezuelan Bolivars (approximately $6.3 million) at a floating interest rate, for financing of Tucupita Pipeline (Incorporated by reference to Exhibit 10.25 to our Form 10-Q, filed on May 15, 2001, File No. 1-10762.).

10.7 Change of Control Severance Agreement effective May 4, 2001 (Incorporated by reference to Exhibit 10.26 to our Form 10-Q, filed on August 13, 2001, File No. 1-10762.).

10.8 Alexander E. Benton Settlement and Release Agreement effective May 11, 2001 (Incorporated by reference to Exhibit 10.27 to our Form 10-Q, filed on August 13, 2001, File No. 1-10762.).

10.9 First Amendment to Change of Control Severance Plan effective June 5, 2001 (Incorporated by reference to Exhibit 10.31 to our Form 10-Q, filed on August 13, 2001, File No. 1-10762.).

10.10 Sale and Purchase Agreement dated February 27, 2002 between Benton Oil and Gas Company and Sequential Holdings Russian Investors Limited regarding the sale of Benton Oil and Gas Company's 68 percent interest in Arctic Gas Company. (Incorporated by reference to Exhibit 10.25 to our Form 10-K filed on March 28, 2002, File No. 1-10762.)

10.11 2001 Long Term Stock Incentive Plan (Incorporated by reference to Exhibit 4.1 to our S-8 (Registration Statement No. 333-85900)).

10.12 Subordinated Loan Agreement US$2,500,000 between Limited Liability Company "Geoilbent" as borrower, and Harvest Natural Resources, Inc. as lender. (Incorporated by reference to Exhibit 10.2 to our Form 10-Q filed on August 13, 2002.)

10.13 Addendum No. 2 to Operating Services Agreement Monagas SUR dated 19th September, 2002. (Incorporated by reference to Exhibit 10.4 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.14 Bank Loan Agreement between Banco Mercantil, C.A. and Benton-Vinccler C.A. dated October 1, 2002. (Incorporated by reference to Exhibit 10.5 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.15 Guaranty issued by Harvest Natural Resources, Inc. dated September 26, 2002. (Incorporated by reference to Exhibit 10.6 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.16 Amending and Restating the Credit Agreement between Limited Liability Company "Geoilbent" and European Bank for Reconstruction and Development dated 23rd September 2002. (Incorporated by reference to Exhibit 10.7 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.17 Amendment Agreement relating to Performance, Subordination and Share Retention Agreement dated 30th September, 2002. (Incorporated by reference to Exhibit 10.8 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.18 Amending and Restating the Agreement for Pledge of Shares in Limited Liability Company "Geoilbent" dated 23rd June, 1997. (Incorporated by reference to Exhibit 10.9 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.19 Employment Agreement dated August 1, 2002 between Harvest Natural Resources, Inc. and Peter J. Hill. (Incorporated by reference to Exhibit 10.10 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.20 Employment Agreement dated August 1, 2002 between Harvest Natural Resources, Inc. and Steven W. Tholen. (Incorporated by reference to Exhibit 10.11 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.21 Employment Agreement dated August 1, 2002 between Harvest Natural Resources, Inc. and Kerry R. Brittain. (Incorporated by reference to Exhibit 10.12 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

10.22 Employment Agreement dated August 1, 2002 between Harvest Natural Resources, Inc. and Kurt A. Nelson. (Incorporated by reference to Exhibit 10.13 to our Form 10-Q filed on November 8, 2002, File No. 1-10762.)

21.1 List of subsidiaries.

23.1 Consent of PricewaterhouseCoopers LLP. - Houston

23.2 Consent of ZAO PricewaterhouseCoopers - Moscow

23.3 Consent of Ryder Scott Company, L.P.

(b) Reports on Form 8-K

On December 11, 2002, we filed an 8-K for a press release dated December 10, 2002, announcing the implementation of an operational contingency plan for the Company's operations in Venezuela.

On December 19, 2002, we filed an 8-K for a press release dated December 18, 2002, reporting that, as a result of the ongoing disruptions in Venezuela, the Company is proceeding with its previously announced operational contingency plan for its operations in Venezuela.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors
and Stockholders of Harvest Natural Resources, Inc.

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Harvest Natural Resources, Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the related financial statement Schedule II – Valuation and Qualifying Accounts listed in the index appearing under Item 15(a)(2) on page 40 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company's total consolidated revenues relate to operations in Venezuela. In addition, the Venezuelan government has implemented foreign currency controls and its economic activities have been impacted by national work stoppages.

PricewaterhouseCoopers LLP

Houston, Texas
March 28, 2003

HARVEST NATURAL RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2001
	(in thousands, except per share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 64,501	$ 9,024
Deposits and restricted cash	1,812	12
Marketable securities	27,388	—
Accounts and notes receivable:		
Accrued oil sales	27,359	23,138
Joint interest and other, net	8,002	9,520
Prepaid expenses and other	2,969	1,839
Total Current Assets	132,031	43,533
Restricted Cash	16	16
Other Assets	2,520	4,718
Deferred Income Taxes	4,082	57,700
Investments In and Advances To Affiliated Companies	51,783	100,498
Property and Equipment:		
Oil and gas properties (full cost method-costs of $2,900 and $16,808 excluded from amortization in 2002 and 2001, respectively)	576,601	533,950
Furniture and fixtures	7,503	7,399
	584,104	541,349
Accumulated depletion, depreciation, and amortization	(439,344)	(399,663)
Net Property and Equipment	144,760	141,686
	$ 335,192	$ 348,151
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable, trade and other	$ 3,804	$ 8,132
Accrued expenses	20,644	25,840
Accrued interest payable	1,405	3,894
Income taxes payable	6,880	3,821
Commodity hedging contract	430	—
Current portion of long-term debt	1,867	2,432
Total Current Liabilities	35,030	44,119
Long-Term Debt	104,700	221,583
Commitments and Contingencies	—	—
Minority Interest	24,145	14,826
Stockholders' Equity:		
Preferred stock, par value $0.01 a share; Authorized 5,000 shares; outstanding, none		
Common stock, par value $0.01 a share; Authorized 80,000 shares at December 31, 2002 and 2001; issued 35,900 and 34,164 at December 31, 2002 and 2001	359	342
Additional paid-in capital	173,559	168,108
Retained earnings (accumulated deficit)	234	(100,128)
Treasury stock, at cost, 650 shares and 50, respectively	(2,835)	(699)
Total Stockholders' Equity	171,317	67,623
	$ 335,192	$ 348,151

See accompanying notes to consolidated financial statements.

HARVEST NATURAL RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2002	2001	2000
	(in thousands, except per share data)		
Revenues			
Oil sales	$ 127,015	$ 122,386	$ 140,284
Loss on ineffective hedge activity	(284)	—	—
	126,731	122,386	140,284
Expenses			
Operating expenses	33,950	42,759	47,430
Depletion, depreciation and amortization	26,363	25,516	17,175
Write-down of oil and gas properties and impairments	14,537	468	1,346
General and administrative	16,504	20,072	16,739
Bad debt recovery	(3,276)	—	—
Taxes other than on income	4,068	5,370	4,390
	92,146	94,185	87,080
Income from Operations	34,585	28,201	53,204
Other Non-Operating Income (Expense)			
Gain on sale of investment	144,029	—	—
Gain on early extinguishment of debt	874	—	3,960
Investment earnings and other	2,080	3,088	8,559
Interest expense	(16,310)	(24,875)	(28,973)
Net gain on exchange rates	4,553	768	326
	135,226	(21,019)	(16,128)
Income from Consolidated Companies Before Income Taxes and Minority Interest	169,811	7,182	37,076
Income Tax Expense (Benefit)	60,295	(35,698)	14,032
Income Before Minority Interest	109,516	42,880	23,044
Minority Interest in Consolidated Subsidiary Companies	9,319	5,545	7,869
Income from Consolidated Companies	100,197	37,335	15,175
Equity in Net Earnings of Affiliated Companies	165	5,902	5,313
Net Income	$ 100,362	$ 43,237	$ 20,488
Net Income Per Common Share:			
Basic	$ 2.90	$ 1.27	$ 0.67
Diluted	$ 2.78	$ 1.27	$ 0.66

See accompanying notes to consolidated financial statements.

HARVEST NATURAL RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(in thousands)

	Common Shares Issued	Common Stock	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Treasury Stock	Total
Balance at January 1, 2000	29,627	$ 296	$ 147,078	$ (163,853)	$ (699)	$ (17,178)
Issuance of common shares:						
Exercise of stock options	85	1	316	-	-	317
Extension of warrants.	-	-	12	-	-	12
Repurchase of debt.........	4,160	42	9,223	-	-	9,265
Net Income.....................	-	-	-	20,488	-	20,488
Balance at December 31, 2000	33,872	339	156,629	(143,365)	(699)	12,904
Issuance of common shares:						
Non-employee director compensation..........	292	3	471	-	-	474
Tax benefits related to stock option compensation	-	-	11,008	-	-	11,008
Net Income.....................	-	-	-	43,237	-	43,237
Balance at December 31, 2001	34,164	342	$ 168,108	$ (100,128)	$ (699)	$ 67,623
Issuance of common shares:						
Non-employee director compensation..........	46	-	543	-	-	543
Employee compensation	175	2	663	-	-	665
Exercise of stock options	1,515	15	4,245	-	-	4,260
Treasury stock (600 shares)	-	-	-	-	(2,136)	(2,136)
Net Income....................	-	-	-	100,362	-	100,362
Balance at December 31, 2002	35,900	$ 359	$ 173,559	$ 234	$ (2,835)	$ 171,317

See accompanying notes to consolidated financial statements.

HARVEST NATURAL RESOURCES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)

	Years Ended December 31,		
	2002	2001	2000
		(in thousands)	
Cash Flows From Operating Activities:			
Net income	$ 100,362	$ 43,237	$ 20,488
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation and amortization	26,363	25,516	17,175
Write-down and impairment of oil and gas properties	14,537	468	1,346
Amortization of financing costs	1,745	1,179	1,375
(Gain) loss on disposition of assets	(144,029)	(336)	60
Equity in net earnings of affiliated companies	(165)	(5,902)	(5,313)
Allowance and write-off of employee notes and accounts receivable	(2,987)	365	331
Non-cash compensation related charges	1,458	474	—
Minority interest in undistributed earnings of subsidiaries	9,319	5,545	7,869
Gain from early extinguishment of debt	(874)	—	(3,960)
Tax benefits related to stock option compensation	—	11,008	—
Deferred income taxes	53,618	(53,407)	7,893
Changes in operating assets and liabilities:			
Accounts and notes receivable	(1,972)	11,756	(12,780)
Prepaid expenses and other	(1,130)	565	(769)
Accounts payable	(4,328)	(4,671)	9,487
Accrued interest payable	(2,489)	161	(953)
Accrued expenses	(10,290)	43	7,971
Commodity hedging contract	430	—	—
Income taxes payable	3,059	607	1,543
Net Cash Provided by Operating Activities	42,627	36,608	51,763
Cash Flows from Investing Activities:			
Proceeds from sale of investment	189,841	—	800
Additions of property and equipment	(43,346)	(43,364)	(57,196)
Investment in and advances to affiliated companies	9,185	(16,855)	(11,071)
Increase in restricted cash	(2,800)	(57)	(271)
Decrease in restricted cash	1,000	10,961	35,800
Purchases of marketable securities	(353,478)	(15,067)	(12,638)
Maturities of marketable securities	326,090	16,370	15,804
Net Cash Provided by (Used In) Investing Activities	126,492	(48,012)	(28,772)
Cash Flows from Financing Activities:			
Net proceeds from exercise of stock options	3,345	—	330
Proceeds from issuance of short term borrowings and notes payable	15,500	21,112	15,087
Payments on short term borrowings and notes payable	(132,138)	(15,746)	(47,488)
(Increase) decrease in other assets	(349)	(70)	3,065
Net Cash Provided by (Used In) Financing Activities	(113,642)	5,296	(29,006)
Net Increase (Decrease) in Cash and Cash Equivalents	55,477	(6,108)	(6,015)
Cash and Cash Equivalents at Beginning of Year	9,024	15,132	21,147
Cash and Cash Equivalents at End of Year	$ 64,501	$ 9,024	$ 15,132
Supplemental Disclosures of Cash Flow Information:			
Cash paid during the year for interest expense	$ 19,201	$ 25,721	$ 28,326
Cash paid during the year for income taxes	$ 3,935	$ 3,057	$ 2,950

See accompanying notes to consolidated financial statements.

Supplemental Schedule of Noncash Investing and Financing Activities:

For the three years ended December 31, 2002, we recorded an allowance for doubtful accounts related to interest accrued on the remaining amount owed to us by our former chief executive officer, A. E. Benton. During the year ended December 31, 2002, we reversed a portion of such allowance as a result of our collection of certain amounts owed to the Company including the portions of the note secured by our stock and other properties *(see Note 13 – Related Party Transactions)*.

See accompanying notes to consolidated financial statements.

HARVEST NATURAL RESOURCES, INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements

Note 1 - Organization and Summary of Significant Accounting Policies

Organization

Harvest Natural Resources, Inc. (formerly known as Benton Oil and Gas Company) is engaged in the exploration, development, production and management of oil and gas properties. We conduct our business principally in Venezuela and through our equity interest in our entity in Russia.

Principles of Consolidation

The consolidated financial statements include the accounts of all wholly-owned and majority-owned subsidiaries. The equity method of accounting is used for companies and other investments in which we have significant influence. All intercompany profits, transactions and balances have been eliminated. We account for our investment in LLC Geoilbent ("Geoilbent") and Arctic Gas Company ("Arctic Gas"), based on a fiscal year ending September 30 *(see Note 2 – Investments In and Advances to Affiliated Companies).*

Revenue Recognition

Oil revenue is accrued monthly based on production and delivery. Each quarter, Benton-Vinccler invoices PDVSA or affiliates based on barrels of oil accepted by PDVSA during the quarter, using quarterly adjusted U.S. dollar contract service fees per barrel. The operating service agreement provides for Benton-Vinccler to receive an operating fee for each barrel of crude oil delivered and the right to receive a capital recovery fee for certain of its capital expenditures, provided that such operating fee and capital recovery fee cannot exceed the maximum total fee per barrel set forth in the agreement. The operating fee is subject to quarterly adjustments to reflect changes in the special energy index of the U.S. Consumer Price Index. The maximum total fee is subject to quarterly adjustments to reflect changes in the average of certain world crude oil prices.

Cash and Cash Equivalents

Cash equivalents include money market funds and short term certificates of deposit with original maturity dates of less than three months.

Restricted Cash

Restricted cash represents cash and cash equivalents used as collateral for financing and letter of credit and loan agreements and is classified as current or non-current based on the terms of the agreements.

Marketable Securities

Marketable securities are carried at cost. The marketable securities we may purchase are limited to those defined as Cash Equivalents in the indentures for our senior unsecured note. Cash Equivalents may be comprised of high-grade debt instruments, demand or time deposits, bankers' acceptances and certificates of deposit or acceptances of large U.S. financial institutions and commercial paper of highly rated U.S. corporations, all having maturities of no more than 180 days. Our marketable securities at cost, which approximates fair value, consisted of $27.4 million in commercial paper at December 31, 2002.

Credit Risk and Operations

All of our total consolidated revenues relate to operations in Venezuela. During the year ended December 31, 2002, our Venezuelan crude oil production represented all of its total production from consolidated companies, and our sole source of revenues related to such Venezuelan production is PDVSA, which maintains full ownership of all hydrocarbons in its fields. On December 2, 2002, employers' and workers' organizations, together with political and civic organizations began a national civic work stoppage, which has seriously affected many of the country's economic activities, in particular, the oil industry. As a result of the strike, we were unable to deliver crude oil and hence generate revenues from PDVSA between December 14, 2002 and February 6, 2003. While Venezuelan production has resumed and we have received payment for its revenues from PDVSA, there continues to be political and economic uncertainty that could lead to another disruption of our revenues. Further, on January 21, 2003, the Venezuelan Government has closed foreign currency markets and announced its intention to implement currency exchange controls aimed at restricting the convertibility of the Venezuelan Bolivar and the transfer of funds out of Venezuela. The Venezuelan Government has created a new Currency Exchange Agency ("CADIVI") which will be responsible for the administration of exchange controls. The closure of the foreign currency markets has limited Benton-Vinccler's ability to obtain Bolivars to make payments to employees and vendors and has restricted our ability to repatriate funds from Venezuela in order to meet our cash requirements. Detailed regulations for exchange controls have not yet been issued by CADIVI. It is not possible to estimate the effects that any further disruptions in Venezuelan crude oil sales or that prolonged currency controls could have on operations and results. Management believes that we have sufficient cash and does not expect the currency conversion restrictions to adversely affect our ability to meet our short-term obligations.

Derivatives and Hedging

We began in the third quarter of 2002 to use a derivative instrument to manage market risk resulting from fluctuations in the commodity price of crude oil. Benton-Vinccler, C.A. *(See Note 10 – Venezuelan Operations)* entered into a commodity contract (costless collar), which requires payments to (or receipts from) counterparties based on a West Texas Intermediate crude oil floor price of $23.00 and a ceiling price of $30.15 for 6,000 barrels of oil per day. The notional amount of this financial instrument is based on expected sales of crude oil production from drilling of the Tucupita development wells. This instrument protects our projected investment return by reducing the impact of an unexpected downward crude oil price movement. The hedge covers expected sales of production for six months beginning in mid-August 2002. Due to the pricing structure of our Venezuelan oil, this collar had the economic effect of hedging approximately 12,000 barrels of oil per day until sales were ceased on December 14, 2002, due to the Venezuelan national civil work stoppage. In order for a derivative instrument to qualify for hedge accounting, there must have been a clear correlation between the derivative instrument and the forecasted transaction. Correlation of the commodity contract was determined by evaluating whether the contract gains and losses would substantially offset the effects of price changes on the underlying crude oil sales volumes. To the extent that correlation exists between the contract and the underlying crude oil sales volumes, realized gains or losses and related cash flows arising from the contracts are recognized as a component of oil revenue in the same period as the sale of the underlying volumes.

This derivative contract has been designated as a cash flow hedge. For all derivatives designated as cash flow hedges, we formally document the relationship between the derivative contract and the hedged item, as well as the risk management objective for entering into the contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and the hedged item must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. We measure the hedge effectiveness on a quarterly basis and hedge accounting is discontinued prospectively if it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item.

Statement of Financial Accounting Standards No. 133, as amended, establishes accounting and reporting standards for derivative instruments and hedging activities. All derivatives are recorded on the balance sheet at fair value. To the extent that the hedge is determined to be effective, as discussed above, changes in the fair value of derivatives for cash flow hedges are recorded each period in other comprehensive income. Our derivative is a cash flow hedge transaction in which we hedge the variability of cash flows related to a forecasted transaction. This derivative instrument was designated as a cash flow hedge and the changes in the fair value will be reported in other comprehensive income assuming the highly effective test is met, and has been reclassified to earnings in the period in which earnings are impacted by the variability of the cash flows of the hedged item. We determined that the underlying crude oil would not be delivered due to the cessation of production. Accordingly, hedge accounting was discontinued and the value of the derivative was recorded as a revenue reduction in the amount of $0.3 million. In connection with this instrument we had deposited collateral of $1.8 million as of December 31, 2002 with the counterparty.

Accounts and Notes Receivable

Allowance for doubtful accounts related to former employee notes at December 31, 2002 and 2001 was $3.5 million and $6.2 million, respectively *(see Note 13 – Related Party Transactions).*

Other Assets

Other assets consist principally of costs associated with the issuance of long-term debt. Debt issuance costs are amortized on a straight-line basis over the life of the debt, which approximates the effective interest method of amortizing these costs.

Property and Equipment

We follow the full cost method of accounting for oil and gas properties with costs accumulated in cost centers on a country-by-country basis. All costs associated with the acquisition, exploration, and development of oil and natural gas reserves are capitalized as incurred, including exploration overhead of $0.6 million and $1.5 million for the years ended December 31, 2001 and 2000, respectively, and capitalized interest of $0.9 million and $0.6 million for the years ended December 31, 2001 and 2000, respectively. There was no capitalized overhead and interest in 2002. Only overhead that is directly identified with acquisition, exploration or development activities is capitalized. All costs related to production, general corporate overhead and similar activities are expensed as incurred.

The costs of unproved properties are excluded from amortization until the properties are evaluated. We regularly evaluate our unproved properties on a country by country basis for possible impairment. If we abandon all exploration efforts in a country where no proved reserves are assigned, all exploration and acquisition costs associated with the country are expensed. During 2002, 2001 and 2000, the Company recognized $14.5 million, $0.5 million and $1.3 million, respectively, of impairment expense associated with certain exploration activities. Due to the unpredictable nature of exploration drilling activities, the amount and timing of impairment expenses are difficult to predict with any certainty.

Excluded costs at December 31, 2002 consisted of the following by year incurred (in thousands):

	Total	Prior to 2000
Property acquisition costs	$ 2,900	$ 2,900

All of the excluded costs at December 31, 2002 relate to the acquisition of Benton Offshore China Company and exploration related to its WAB-21 property. The ultimate timing of when the costs related to the acquisition of Benton Offshore China Company will be included in amortizable costs is uncertain.

All capitalized costs and estimated future development costs (including estimated dismantlement, restoration and abandonment costs) of proved reserves are depleted using the units of production method based on the total proved reserves of the country cost center. Depletion expense, which was substantially all attributable to the Venezuelan cost center for the years ended December 31, 2002, 2001 and 2000 was $24.9 million, $22.1 million and $15.3 million ($2.56, $2.26 and $1.68 per equivalent barrel), respectively.

A gain or loss is recognized on the sale of oil and gas properties only when the sale involves a significant change in the relationship between costs and the value of proved reserves or the underlying value of unproved property.

Depreciation of furniture and fixtures is computed using the straight-line method with depreciation rates based upon the estimated useful life of the property, generally 5 years. Leasehold improvements are depreciated over the life of the applicable lease. Depreciation expense was $1.4 million, $3.4 million and $1.8 million for the years ended December 31, 2002, 2001 and 2000, respectively.

The major components of property and equipment at December 31 are as follows (in thousands):

	2002	2001
Proved property costs	$ 566,415	$ 501,923
Costs excluded from amortization	2,900	16,808
Material and supply inventories	7,286	15,219
Furniture and fixtures	7,503	7,399
	584,104	541,349
Accumulated depletion, impairment and depreciation	(439,344)	(399,663)
	$ 144,760	$ 141,686

We perform a quarterly cost center ceiling test of our oil and gas properties under the full cost accounting rules of the Securities and Exchange Commission. No ceiling test write-downs were required.

Income Taxes

Deferred income taxes reflect the net tax effects, calculated at currently enacted rates, of (a) future deductible/taxable amounts attributable to events that have been recognized on a cumulative basis in the financial statements or income tax returns, and (b) operating loss and tax credit carryforwards. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized. In the fourth quarter of 2001, a substantial portion of the valuation allowance was reversed based on the utilization of net operating losses by the Arctic Gas Sale in 2002.

Foreign Currency

We have significant operations outside of the United States, principally in Venezuela and an equity investment in Russia. Amounts denominated in non-U.S. currencies are re-measured in United States dollars, and all currency gains or losses are recorded in the statement of income. We attempt to manage our operations in a manner to reduce our exposure to foreign exchange losses. However, there are many factors that affect foreign exchange rates and resulting exchange gains and losses, many of which are beyond our influence. We have recognized significant exchange gains and losses in the past, resulting from fluctuations in the relationship of the Venezuelan and Russian currencies to the United States dollar. It is not possible to predict the extent to which we may be affected by future changes in exchange rates.

In November 2002, the International Practices Task Force (IPTF) concluded that Russia has ceased being a highly inflationary economy as of January 1, 2003. As a result of the Task Force conclusion, companies reporting under US GAAP in Russia will be required to apply the guidance contained in EITF No. 92-4 and EITF No. 92-8 as of January 1, 2003. We have not yet estimated the effect that EITF No. 92-4 and EITF No. 92-8 will have on Geoilbent or our equity position.

Financial Instruments

Our financial instruments that are exposed to concentrations of credit risk consist primarily of cash and cash equivalents, marketable securities and accounts receivable. Cash and cash equivalents are placed with commercial banks with high credit ratings. This diversified investment policy limits our exposure both to credit risk and to concentrations of credit risk. Accounts receivable result from oil and natural gas exploration and production activities and our customers and partners are engaged in the oil and natural gas business. PDVSA purchases 100 percent of our Venezuelan oil and gas production. Although the Company does not currently foresee a credit risk associated with these receivables, collection is dependent upon the financial stability of PDVSA. The payment for the fourth quarter 2002 sales was delayed until March 7, 2003, which was approximately seven days late due to the effect of the national civil work stoppage on PDVSA.

The book values of all financial instruments, other than long-term debt, are representative of their fair values due to their short-term maturities. The aggregate fair value of our senior unsecured notes, based on the last trading prices at December 31, 2002 and 2001, was approximately $77.4 million and $138.1 million, respectively.

Comprehensive Income

Statement of Financial Accounting Standards No. 130 ("SFAS 130") requires that all items that are required to be recognized under accounting standards as components of comprehensive income be reported in a financial statement that is displayed with the same prominence as other financial statements. We did not have any items of other comprehensive income during the three years ended December 31, 2002 and, in accordance with SFAS 130, have not provided a separate statement of comprehensive income.

Minority Interests

We record a minority interest attributable to the minority shareholder of our Venezuela subsidiaries. The minority interests in net income and losses are generally subtracted or added to arrive at consolidated net income.

New Accounting Pronouncements

In September 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS No. 143). SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost should be allocated to expense using a systematic and rational method. SFAS No. 143 is effective for fiscal years beginning after September 15, 2002. We will adopt SFAS No. 143 effective January 1, 2003 and such adoption will not materially impact the financial statements since our PDVSA operating service agreement provides that all wells revert to PDVSA at contract expiration and intervening abandonment obligations are minor. Accordingly, all gains on early extinguishment of debt have been reclassified to other non-operating income in the accompanying consolidated financial statements.

In May 2002, the FASB issued SFAS No. 145, Recission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections". SFAS 145 rescinds the automatic treatment of gains or losses from extinguishment of debt as extraordinary items as outlined in APB Opinion No. 30, "Reporting the Results of Operations, Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions". As allowed under the provisions of SFAS 145, we had decided to adopt SFAS 145 early *(See Note 3 – Long Term Debt and Liquidity)*.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities". The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing, or other exit or disposal activity. SFAS 146 replaces Emerging Issues Task Force Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)". The provisions of this statement shall be effective for exit or disposal activities initiated after December 31, 2002. The Company will account for exit or disposal activities initiated after December 31, 2002, in accordance with the provisions of SFAS No. 146.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure an amendment of FASB Statement No. 123". The standard amends SFAS No. 123 that provides alternative methods of transition for an entity that voluntarily changes to the fair value based method of accounting for stock-based employee compensation. In addition, this statement amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The Company intends to adopt the "Prospective method" which will apply the recognition provisions to all employee awards granted, modified, or settled in 2003.

The weighted average fair value of the stock options granted from our stock option plans during 2002, 2001 and 2000 was \$4.84, \$1.33 and \$1.65, respectively. The fair value of each stock option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted average assumptions used:

	2002	2001	2000
Expected life	10.0 years	10.0 years	9.1 years
Risk-free interest rate	5.0%	5.1%	6.1%
Volatility	74%	72%	74%
Dividend Yield	0%	0%	0%

We accounted for stock-based compensation in accordance with Accounting Principles Board Opinion No. 25 and related interpretations, under which no compensation cost has been recognized for stock option awards. Had compensation cost for the plans been determined consistent with SFAS 123, our pro forma net income and earnings per share for 2002, 2001 and 2000 would have been as follows (in thousands, except per share data):

	2002	2001	2000
Net income as reported	$100,362	$ 43,237	$ 20,488
Add: Stock-based employee compensation expense included in reported net income due to acceleration of vesting of former employees	915	35	110
Deduct: Total stock-based employee compensation expense determined under fair value based method for all grants awarded since January 1, 1995	(2,905)	(2,459)	(4,374)
Net income	$ 98,372	$ 40,813	$ 16,224
Net income per common share:			
Basic	$ 2.87	$ 1.20	$ 0.53
Diluted	$ 2.75	$ 1.20	$ 0.53

In November 2002 FASB interpretation, or FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantee of Indebtedness of Others" was issued. FIN 45 requires that upon issuance of a guarantee, the guarantor must recognize a liability for the fair value of the obligation it assumes under that guarantee. FIN 45's provisions for initial recognition and measurement should be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The guarantor's previous accounting for guarantees that were issued before the date of FIN 45's initial application may not be revised or restated to reflect the effect of the recognition and measurement provisions of FIN 45. The disclosure requirements are effective for financial statements of both interim and annual periods that end after December 15, 2002. As of December 31, 2002, the Company does not have any guarantor obligations.

In January 2003 FASB Interpretation 46, or FIN 46, "Consolidation of Variable Interest Entities" was issued. FIN 46 identifies certain off-balance sheet arrangements that meet the definition of a variable interest entity (VIE). The primary beneficiary of a VIE is the party that is exposed to the majority of the risks and/or returns of the VIE. In future accounting periods, the primary beneficiary will be required to consolidate the VIE. In addition, more extensive disclosure requirements apply to the primary beneficiary, as well as other significant investors. We do not believe we participate in any arrangement that would be subject to the provisions of FIN 46.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, plant products and gas reserve volumes and the future development costs. Actual results could differ from those estimates.

Reclassifications

Certain items in 2000 and 2001 have been reclassified to conform to the 2002 financial statement presentation.

Note 2 - Investments In and Advances To Affiliated Companies

Investments in Geoilbent and Arctic Gas are accounted for using the equity method due to the significant influence we exercise over their operations and management. Investments include amounts paid to the investee companies for shares of stock and other costs incurred associated with the acquisition and evaluation of technical data for the oil and natural gas fields operated by the investee companies. Other investment costs are amortized using the units of production method based on total proved reserves of the investee companies. Equity in earnings of Geoilbent and Arctic Gas are based on a fiscal year ending September 30. Arctic Gas was sold on April 12, 2002.

Equity in earnings and losses and investments in and advances to companies accounted for using the equity method are as follows (in thousands):

	Geoilbent, Ltd.		Arctic Gas Company		Total	
	2002	2001	2002	2001	2002	2001
Investments:						
In equity in net assets	$ 28,056	$ 28,056	$ —	$ (1,814)	$ 28,056	$ 26,242
Other costs, net of amortization	263	(99)	—	28,579	263	28,480
Total investments	28,319	27,957	—	26,765	28,319	54,722
Advances	2,527	-	—	28,829	2,527	28,829
Equity in earnings (losses)	20,937	19,307	—	(2,360)	20,937	16,947
Total	$ 51,783	$ 47,264	$ —	$ 53,234	$ 51,783	$100,498

Note 3 - Long-Term Debt and Liquidity

Long-Term Debt

Long-term debt consists of the following (in thousands):

	December 31, 2002	December 31, 2001
Senior unsecured notes with interest at 9.375% See description below	$ 85,000	$ 105,000
Senior unsecured notes with interest at 11.625% See description below	—	108,000
Note payable with interest at 6.8% See description below	3,900	5,100
Note payable with interest at 39.7% See description below	2,167	5,235
Note payable with interest at 7.8%	15,500	—
Non-interest bearing liability with a face value of $744 discounted at 7%. See description below	—	680
	106,567	224,015
Less current portion	1,867	2,432
	$ 104,700	$ 221,583

At December 31, 2001, we had $108.0 million in 11.625 percent senior unsecured notes due in May 1, 2003, all of which have been redeemed, which resulted in a gain of $0.9 million in 2002. In November 1997, we issued $115.0 million in 9.375 percent senior unsecured notes due November 1, 2007 ("2007 Notes"), of which we repurchased $30.0 million. Interest on the 2007 Notes is due May 1 and November 1 of each year. At December 31, 2002, we were in compliance with all covenants of the indenture.

In March 2001, Benton-Vinccler borrowed $12.3 million from a Venezuelan commercial bank, for construction of an oil pipeline. The loan is in two parts, with the first part in an original principal amount of $6.0 million that bears interest payable monthly based on 90-day London Interbank Borrowing Rate ("LIBOR") plus 5 percent with principal payable quarterly for five years. The second part, in the original principal amount of 4.4 billion Venezuelan Bolivars ("Bolivars") (approximately $6.3 million), bears interest payable monthly based on a mutually agreed interest rate determined quarterly, or a six-bank average published by the central bank of Venezuela. The interest rate for the quarter ending December 31, 2002 was 39.7 percent with a negative effective interest rate taking into account exchange gains resulting from the devaluation of the Bolivar during the year. The loans provide for certain limitations on mergers and sale of assets. The Company has guaranteed the repayment of this loan

On October 1, 2002, Benton-Vinccler, C.A. executed a note and borrowed $15.5 million to fund construction of a gas pipeline and related facilities to deliver natural gas from the Uracoa field to a PDVSA pipeline. The interest rate for this loan is LIBOR plus 6 percentage points determined quarterly. The term is four years with a one year debt service grace period to coincide with our gas sales and a quarterly amortization of $1.3 million.

Benton-Vinccler's oil and gas pipeline project loans allow the lender to accelerate repayment if production ceases for a period greater than thirty days. During the production shut-in which started in December 2002, Benton-Vinccler was granted a waiver of this provision until February 18, 2003 for a prepayment of the next two principal obligations aggregating $0.9 million. This prepayment, while using cash reserves, reduces our net interest expense as the current interest expense was more than the current interest income earned on the invested funds. On February 8, 2003, Benton-Vinccler commenced production, thereby eliminating the need for an additional waiver. A future disruption of production could trigger the debt acceleration provision again. While no assurances can be given, we believe Benton-Vinccler would be able to obtain another waiver.

In 2001, a dispute arose over collection by municipal taxing regimes on the Uracoa, Bombal and Tucupita Fields that comprise the South Monagas Unit resulting in overpayments and underpayments to adjacent municipalities. As settlement, a portion of future municipal tax payments will be offset by the municipal tax that was originally overpaid. The present value of the long-term portion of the settlement liability is $0.7 million at December 31, 2001. *The entire balance was repaid by December 31, 2002.*

The principal payment requirements for our long-term debt outstanding at December 31, 2002 are as follows (in thousands):

2003	$ 1,867
2004	7,035
2005	7,035
2006	5,630
2007	85,000
	$ 106,567

Liquidity

We currently have a significant debt obligation payable in November 2007 of $85 million. Our ability to meet our debt obligations and to reduce our level of debt depends on the successful implementation of our strategic objectives. Our cash flow from operations complemented with our cash and cash equivalents of $91.9 million at December 31, 2002, can be invested in other opportunities used to develop our significant proved undeveloped reserves or used to repurchase our outstanding debt.

Note 4 - Commitments and Contingencies

We have employment contracts with four executive officers which provide for annual base salaries, eligibility for bonus compensation and various benefits. The contracts provide for a lump sum payment as a multiple of base salary in the event of termination of employment without cause. In addition, these contracts provide for payments as a multiple of base salary and bonus, tax reimbursement and a continuation of benefits in the event of termination without cause following a change in control of the Company. By providing one year notice, these agreements may be terminated by either party on May 31, 2004.

In July 2001, we leased for three years office space in Houston, Texas for approximately $11,000 per month. We lease 17,500 square feet of space in a California building that we no longer occupy under a lease agreement that expires in December 2004, all of which has been subleased for rents that approximate our lease costs.

The Company is a defendant in or otherwise involved in litigation incidental to its business. In the opinion of management, there is no litigation which is material to the Company.

Note 5 - Taxes

Taxes Other Than on Income

Benton-Vinccler pays a municipal tax on operating fee revenues it receives for production from the South Monagas Unit. The components of taxes other than on income were (in thousands):

	2002	2001	2000
Venezuelan municipal taxes	$ 3,805	$ 4,447	$ 3,164
Severance and production taxes	-	-	28
Franchise taxes	139	121	131
Payroll and other taxes	124	802	1,067
	$ 4,068	$ 5,370	$ 4,390

Taxes on Income

The tax effects of significant items comprising our net deferred income taxes as of December 31, 2002 and 2001 are as follows (in thousands):

	2002	2001
Deferred tax assets:		
Operating loss carryforwards	$ 19,690	$ 49,000
Difference in basis of property	21,495	19,300
Other	2,043	9,100
Valuation allowance	(39,146)	(19,700)
Net deferred tax asset	$ 4,082	$ 57,700

The valuation allowance increased by $19.4 million as a result of the increase in the U.S. deferred tax assets related to the net operating loss carryforward. Realization of deferred tax assets associated with net operating loss carryforwards is dependent upon generating sufficient taxable income prior to their expiration. Management believes it is more likely than not that they will be realized through future taxable income.

The components of income before income taxes, minority interest and extraordinary items are as follows (in thousands):

	2002	2001	2000
Income (loss) before income taxes			
United States	$ 89,455	$ (26,572)	$ (9,074)
Foreign	80,356	33,754	46,150
Total	$ 169,811	$ 7,182	$ 37,076

The provision (benefit) for income taxes consisted of the following at December 31, (in thousands):

	2002	2001	2000
Current:			
United States	$ 353	$ 1	$ 215
Foreign	6,324	6,700	5,925
	$ 6,677	$ 6,701	$ 6,140
Deferred:			
United States	$ 53,413	$ (42,405)	—
Foreign	205	6	7,892
	53,618	(42,399)	7,892
	$ 60,295	$ (35,698)	$ 14,032

A comparison of the income tax expense (benefit) at the federal statutory rate to our provision for income taxes is as follows (in thousands):

	2002	2001	2000
Computed tax expense at the statutory rate	$ 59,348	$ 4,580	$ 13,451
State income taxes	353	—	(343)
Effect of foreign source income and rate differentials on foreign income	(19,373)	1,675	(1,826)
Change in valuation allowance	19,446	(53,413)	2,294
Prior year adjustments	—	2,304	1,637
Reclass paid-in capital	—	11,007	—
All other	80	215	679
Sub-total income tax expense (benefit)	59,854	(33,632)	15,892
Effects of recording equity income of certain affiliated Companies on an after-tax basis	441	(2,066)	(1,860)
Total income tax expense (benefit)	$ 60,295	$ (35,698)	$ 14,032

Rate differentials for foreign income result from tax rates different from the U.S. tax rate being applied in foreign jurisdictions and from the effect of foreign currency devaluation in foreign subsidiaries which use the U.S. dollar as their functional currency.

At December 31, 2002, we had, for federal income tax purposes, operating loss carryforwards of approximately $56.3 million, expiring in the years 2011 through 2022.

We do not provide deferred income taxes on undistributed earnings of international consolidated subsidiaries for possible future remittances as all such earnings are reinvested as part of our ongoing business.

Note 6 - Stock Option and Stock Purchase Plans

In January 2001, we adopted the Non-Employee Director Stock Purchase Plan (the "Stock Purchase Plan") to encourage our directors to acquire a greater proprietary interest in our company through the ownership of our common stock. Under the Stock Purchase Plan each non-employee director could elect to receive shares of our common stock for all or a portion of their fee for serving as a director. The number of shares issuable is equal to 1.5 times the amount of cash compensation due the director divided by the fair market value of the common stock on the scheduled date of payment of the applicable director's fee. The shares have a restriction upon their sale for one year from the date of issuance. As of December 31, 2002, 337,850 shares had been issued from the plan. The Stock Purchase Plan was terminated by the Board of Directors in September 2002.

In July 2001, our shareholders approved the adoption of the 2001 Long Term Stock Incentive Plan. The 2001 Long Term Stock Incentive Plan provides for grants of options to purchase up to 1,697,000 shares of our common stock in the form of Incentive Stock Options and Non-qualified Stock Options to eligible participants including employees of our company or subsidiaries, directors, consultants and other key persons. The exercise price of stock options granted under the plan must be no less than the fair market value of our common stock on the date of grant. No officer may be granted more than 500,000 options during any one fiscal year, as adjusted for any changes in capitalization, such as stock splits. In the event of a change in control of our company, all outstanding options become immediately exercisable to the extent permitted by the plan. All options granted to date vest ratably over a three-year period from their dates of grant and expire ten years from grant date.

Since 1989 we have adopted several other stock option plans under which options to purchase shares of our common stock have been granted to employees, officers, directors, independent contractors and consultants. Options granted under these plans have been at prices equal to the fair market value of the stock on the grant dates. Options granted under the plans are generally exercisable in varying cumulative periodic installments after one year cannot be exercised more than ten years after the grant dates. Following the adoption of the 2001 Long Term Stock Incentive Plan, no options may be granted under any of these plans.

A summary of the status of our stock option plans as of December 31, 2002, 2001 and 2000 and changes during the years ending on those dates is presented below (shares in thousands):

	2002		2001		2000	
	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares
Outstanding at beginning of the year:	$ 6.36	6,865	$ 7.74	5,660	$ 7.55	6,300
Options granted	4.84	165	1.65	1,684	2.06	240
Options exercised	2.21	(1,515)	—	—	2.53	(85)
Options cancelled	8.03	(292)	6.43	(479)	4.90	(795)
Outstanding at end of the year	7.42	5,223	6.36	6,865	7.74	5,660
Exercisable at end of the year	8.49	4,360	8.32	4,800	9.68	4,099

Significant option groups outstanding at December 31, 2002 and related weighted average price and life information follow:

	Outstanding			Exercisable	
Range of Exercise Prices	Number Outstanding At December 31, 2002	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at December 31, 2002	Weighted-Average Exercise Price
$ 1.55 - $ 2.75	2,475,149	7.70	$ 1.97	1,737,066	$ 2.09
$ 4.89 - $ 7.00	520,333	4.38	5.77	395,333	6.07
$ 7.25 - $11.00	660,633	3.16	8.88	660,633	8.88
$11.50 - $16.50	1,071,665	3.91	13.58	1,071,665	13.58
$17.38 - $24.13	494,833	4.05	21.13	494,833	21.13
	5,222,613			4,359,530	

Of the number outstanding, 1,233,750 options are controlled by the company through the A. E. Benton settlement. *See Note 13 – Related Party Transactions.*

In connection with our acquisition of Benton Offshore China Company in December 1996, we adopted the Benton Offshore China Company 1996 Stock Option Plan. Under the plan, Benton Offshore China Company is authorized to issue up to 107,571 options to purchase our common stock for $7.00 per share. The plan was adopted in substitution of Benton Offshore China Company's stock option plan, and all options to purchase shares of Benton Offshore China Company common stock were replaced under the plan by options to purchase shares of our common stock. All options were issued upon the acquisition of Benton Offshore China Company and vested upon issuance. At December 31, 2002, options to purchase 74,427 shares of common stock were both outstanding and exercisable.

In addition to options issued pursuant to the plans, options have been issued to individuals other than officers, directors or employees of the Company at prices ranging from $5.63 to $11.88 which vest over three to four years. At December 31, 2002, a total of 192,500 options issued outside of the plans were both outstanding and exercisable.

Note 7 - Stock Warrants

The dates the warrants were issued, the expiration dates, the exercise prices and the number of warrants issued and outstanding at December 31, 2002 were (warrants in thousands):

			Warrants	
Date Issued	Expiration Date	Exercise Price	Issued	Outstanding
July 1994	July 2004	$ 7.50	150	8
December 1994	December 2004	12.00	50	50
June 1995	June 2007	17.09	125	125
			325	183

Note 8 - Operating Segments

We regularly allocate resources to and assess the performance of our operations by segments that are organized by unique geographic and operating characteristics. The segments are organized in order to manage regional business, currency and tax related risks and opportunities. Revenue from Venezuela is derived primarily from the production and sale of oil. Other income from USA and other is derived primarily from interest earnings on various investments and consulting revenues. Operations included under the heading "USA and Other" include corporate management, exploration activities, cash management and financing activities performed in the United States and other countries which do not meet the requirements for separate disclosure. All intersegment revenues, other income and equity earnings, expenses and receivables are eliminated in order to reconcile to consolidated totals. Corporate general and administrative and interest expenses are included in the USA and Other segment and are not allocated to other operating segments.

Year ended December 31, 2002: (in thousands)	Venezuela	USA and Other	Russia	Eliminations	Consolidated
Revenues					
Oil sales	$ 127,015	$ -	$ -	$ -	$ 127,015
Other comprehensive loss: hedge	(284)	-	-	-	(284)
	126,731	-	-	-	126,731
Expenses					
Operating expenses	31,457	360	2,133	-	33,950
Depletion, depreciation and amortization	23,850	2,483	30	-	26,363
General and administrative	4,310	11,420	774	-	16,504
Bad debt recovery	-	(3,276)	-	-	(3,276)
Taxes other than on income	3,997	71	-	-	4,068
Total expenses	63,614	11,058	2,937	-	77,609
Income (loss) from operations	63,117	(11,058)	(2,937)	-	49,122
Other non-operating income (expense)					
Gain on sale of investment	-	144,032	(3)	-	144,029
Gain on early extinguishment of debt	-	874	-	-	874
Investment earnings and other	1,889	1,653	-	(1,462)	2,080
Interest expense	(4,237)	(13,611)	-	1,538	(16,310)
Net gain on exchange rates	4,356	197	-	-	4,553
Intersegment revenues (expenses)	15,156	(15,156)	-	-	-
Equity in income of affiliated companies	-	-	165	-	165
	17,164	117,989	162	76	135,391
Income (loss) before income taxes	80,281	106,931	(2,775)	76	184,513
Income tax expense	6,453	53,764	2	76	60,295
Operating segment income (loss)	73,828	53,167	(2,777)	-	124,218
Write-down of oil and gas properties and impairments	-	(14,537)	-	-	(14,537)
Minority interest	(9,319)	-	-	-	(9,319)
Net income (loss)	$ 64,509	$ 38,630	$ (2,777)	$ -	$ 100,362
Total assets	$ 209,733	$ 122,355	$ 52,302	$ (49,198)	$ 335,192
Additions to properties	$ 42,486	$ 738	$ 122	$ -	$ 43,346

Year ended December 31, 2001:
(in thousands)

	Venezuela	USA and Other	Russia	Eliminations	Consolidated
Revenues					
Oil sales	$ 122,386	$ -	$ -	$ -	$ 122,386
Expenses					
Operating expenses	42,037	55	667	-	42,759
Depletion, depreciation and amortization	22,096	3,408	12	-	25,516
General and administrative	4,151	14,972	949	-	20,072
Taxes other than on income	4,666	704	-	-	5,370
Total expenses	72,950	19,139	1,628	-	93,717
Income (loss) from operations	49,436	(19,139)	(1,628)	-	28,669
Other non-operating income (expense):					
Investment earnings and other	5,995	2,053	60	(5,020)	3,088
Interest expense	(7,403)	(22,695)	-	5,223	(24,875)
Net gain on exchange rates	732	36	-	-	768
Intersegment revenues (expenses)	(14,983)	14,983	-	-	-
Equity in income of affiliated companies	-	-	5,902	-	5,902
	(15,659)	(5,623)	5,962	203	(15,117)
Income (loss) before income taxes	33,777	(24,762)	4,334	203	13,552
Income tax (benefit) expense	6,491	(42,392)	-	203	(35,698)
Operating segment income	27,286	17,630	4,334	-	49,250
Write-down of oil and gas properties and impairments	-	(468)	-	-	(468)
Minority interest	(5,545)	-	-	-	(5,545)
Net income	$ 21,741	$ 17,162	$ 4,334	$ -	$ 43,237
Total assets	$ 167,671	$ 165,254	$ 100,801	$ (85,575)	$ 348,151
Additions to properties	$ 43,411	$ -	$ 31	$ -	$ 43,442

Year ended December 31, 2000:
(in thousands)

	Venezuela	USA and Other	Russia	Eliminations	Consolidated
Revenues					
Oil and natural gas sales	$ 139,890	$ 394	$ -	$ -	$ 140,284
	139,890	394	-	-	140,284
Expenses					
Operating expenses	46,727	59	644	-	47,430
Depletion, depreciation and amortization	16,285	879	11	-	17,175
General and administrative	3,659	12,014	1,066	-	16,739
Taxes other than on income	3,355	1,048	(13)	-	4,390
Total expenses	70,026	14,000	1,708	-	85,734
Income (loss) from operations	69,864	(13,606)	(1,708)	-	54,550
Other non-operating income (expense):					
Investment earnings and other	1,392	8,986	-	(1,819)	8,559
Interest expense	(6,131)	(24,661)	-	1,819	(28,973)
Net gain on exchange rates	298	28	-	-	326
Intersegment revenues (expenses)	(12,226)	12,226	-	-	-
Equity in income of affiliated companies	-	-	5,313	-	5,313
	(16,667)	(3,421)	5,313	-	(14,775)
Income (loss) before income taxes	53,197	(17,027)	3,605	-	39,775
Income tax expense	14,020	12	-	-	14,032
Operating segment income (loss)	39,177	(17,039)	3,605	-	25,743
Write-down of oil and gas properties and impairments	-	(1,346)	-	-	(1,346)
Minority interest	(7,869)	-	-	-	(7,869)
Extraordinary income on debt repurchase	-	3,960	-	-	3,960
Net income (loss)	$ 31,308	$ (14,425)	$ 3,605	$ -	$ 20,488
Total assets	$ 166,462	$ 156,780	$ 78,406	$ (115,201)	$ 286,447
Additions to properties	$ 54,112	$ 3,075	$ 9	$ -	$ 57,196

Note 9 - Russian Operations

Geoilbent

We own 34 percent of Geoilbent, a Russian limited liability company formed in 1991 to develop, produce and market crude oil from the North Gubkinskoye and South Tarasovskoye fields in the West Siberia region of Russia. Our investment in Geoilbent is accounted for using the equity method. Sales quantities attributable to Geoilbent for the years ended September 30, 2002, 2001 and 2000 were 6.9 million Bbls, (4.6 million domestic and

2.3 million export) 5.2 million Bbls, (0.8 million domestic and 4.4 million export) and 4.2 million Bbls, respectively. Prices for crude oil for the years ended September 30, 2002, 2001 and 2000 averaged $13.25 ($8.89 domestic and $21.73 export), $19.51 ($13.69 domestic and $20.48 export) and $18.56 per barrel, respectively. Depletion expense attributable to Geoilbent for the years ended September 30, 2002, 2001 and 2000 was $3.93, $2.88 and $2.25 per barrel, respectively. Summarized financial information for Geoilbent follows (in thousands). All amounts represent 100 percent of Geoilbent.

Year ended September 30:	2002	2001	2000
Revenues			
Oil sales	$ 91,598	$ 101,159	$ 78,805
Expenses			
Selling and distribution expenses	6,696	9,876	4,612
Operating expenses	15,360	11,415	8,959
Depletion, depreciation and amortization	27,168	14,918	9,556
General and administrative	8,335	5,650	3,407
Taxes other than on income	27,657	26,011	18,286
	85,216	67,870	44,820
Income from operations	6,382	33,289	33,985
Other non-operating income (expense)			
Investment earnings and other	381	648	(724)
Interest expense	(4,629)	(7,547)	(7,438)
Net gain (loss) on exchange rates	2,053	781	(597)
	(2,195)	(6,118)	(8,759)
Income before income taxes	4,187	27,171	25,226
Income tax expense	302	6,751	6,321
Net income	$ 3,885	$ 20,420	$ 18,905
At September 30:			
Current assets	$ 18,785	$ 35,447	$ 30,979
Other assets	186,815	187,706	163,332
Current liabilities	54,051	60,439	36,567
Other liabilities	7,500	22,550	38,000
Net equity	144,049	140,164	119,744

The European Bank for Reconstruction and Development ("EBRD") and International Moscow Bank ("IMB") together agreed in 1996 to lend up to $65 million to Geoilbent, based on achieving certain reserve and production milestones, under parallel reserve-based loan agreements. As of September 30, 2002, the outstanding balance of the loan with EBRD was $22 million and the IMB portion was $0.6 million which was repaid in November 2002. By agreement dated September 23, 2002, the loan agreement with EBRD was restructured into a revolving credit agreement, with up to $50.0 million available, including the $22 million already outstanding. The interest rate for the restructured loan is six-month LIBOR plus 4.75 percent, with additional interest up to 3 percent during the term portion of the loan based upon Geoilbent's net income. Principal payments are due in six equal semiannual installments beginning January 27, 2004. The restructured loan agreement grants EBRD a security interest in the assets of Geoilbent and requires that Geoilbent meet certain financial ratios and covenants, including a minimum current ratio. As of September 30, 2002, Geoilbent was not in compliance with the current 1:1 ratio requirement, but had received a waiver from EBRD through the quarters ended September 30, 2002. The loan agreement also provides for certain limitations on liens, additional indebtedness, certain investments, capital expenditures, dividends, mergers and sales of assets. In addition, the Company and Minley, have pledged their ownership interests in Geoilbent as security for the debt, and agreed to support Geoilbent in its obligations under the loan agreement, including providing technical and managerial personnel and resources to develop its fields. Under these agreements, the Company and Minley are each jointly and severally liable to EBRD for any losses, damages, liabilities, costs, expenses and other amounts suffered or sustained arising out of any breach by the other of its support obligations. As available, proceeds from the restructured loan will be used to reduce payables and to develop the South Tarasovskoye Field.

The waiver from EBRD of the current ratio requirement expires March 31, 2003. On March 12, 2003 Geoilbent drew $8.0 million under the loan to reduce payables, there can be no assurance that the draw will be adequate to permit Geoilbent to meet the ratio requirement. If Geoilbent fails to meet the ratio requirements for two consecutive quarters it will result in an event of default whereby EBRD may, at its option, demand payment of the outstanding principal and interest. In addition, the restructured loan agreement requires that Geoilbent implement a new management information system by May 1, 2003. Geoilbent will be unable to timely satisfy this requirement which also results in an event of default whereby EBRD may, at its option, demand payment of the outstanding principal and interest.

At September 30, 2002, and September 30, 2001, the current liabilities of Geoilbent exceeded its current assets by $35.3 million and $25.7 million, respectively. Included in current liabilities as of September 30, 2002 are loans repayable to EBRD ($22.0 million) and IMB ($0.6 million). This debt has been classified as current because Geoilbent will not be able to implement a new management information system as required by the EBRD loan facility. As a result of this situation, Geoilbent's independent accountants have indicated in their report that substantial doubt exists regarding Geoilbent's ability to meet its debts as they come due. While no assurance can be given, the Company believes these covenant defaults are temporary and does not result in an other than temporary decline in the Company's investment in Geoilbent or will cause EBRD to declare a default after considering Geoilbent's historical net income, cash flow from operating activities and other matters.

Because of Geoilbent's significant working capital deficit, a substantial portion of its cash flow must be utilized to reduce accounts and taxes payable. Additionally, in order to maintain or increase proved oil and gas reserves, Geoilbent must make substantial capital expenditures in 2003. Geoilbent's net cash provided by operating activities is dependent on the level of oil prices, which are historically volatile and are significantly impacted by the proportion of production that Geoilbent can sell on the export market. Historically, Geoilbent has supplemented its cash flow from operations with additional borrowings or equity capital and may need to continue to do so. Should oil prices decline for a prolonged period or should Geoilbent not have access to additional capital, Geoilbent would need to reduce its capital expenditures, which could limit its ability to maintain or increase production and, in turn, meet its debt service requirements. Asset sales and financing are restricted under the terms of the EBRD loan.

Geoilbent management plans to further address the working capital deficit by reducing certain capital expenditures and funding its 2003 debt service and planned capital expenditures with cash flows from existing producing properties and its development drilling program. At December 31, 2002, Geoilbent had accounts payable outstanding of $12.2 million of which approximately $5.9 million was 90 days or more past due. The amounts outstanding were primarily to contractors and vendors for drilling and construction services. Under Russian law, creditors, to whom payments are 90 days or more past due, can force a company into involuntary bankruptcy. Geoilbent's financial statements do not include any adjustments that might result if Geoilbent were unable to continue as a going concern.

As of September 30, 2002, the Geoilbent ($2.5 million from Harvest and $5.0 million from Minley) shareholders had provided Geoilbent with subordinated loans totaling $7.5 million. These loans are unsecured and repayable commencing in January 2004. Our interest rate is based on LIBOR up to January 2004, and rises from 8 to 12 percent thereafter. There can be no assurance that Geoilbent will have the ability to repay the loan made by the Company when due.

Arctic Gas Company

In April 1998, we signed an agreement to earn a 40 percent equity interest in Arctic Gas Company, formerly Severneftegaz. Arctic Gas owns the exclusive rights to evaluate, develop and produce the natural gas, condensate and oil reserves in the Samburg and Yevo-Yakha license blocks in West Siberia. The two blocks comprise 794,972 acres within and adjacent to the Urengoy Field, Russia's largest producing natural gas field. Under the terms of a Cooperation Agreement between us and Arctic Gas, we will earn a 40 percent equity interest in exchange for providing or arranging for a credit facility of up to $100 million for the project, the terms and timing of which were finalized in February 2002. We received voting shares representing 40 percent ownership in Arctic Gas that contain restrictions on their sale and transfer. A Share Disposition Agreement provides for removal of the restrictions as disbursements are made under the credit facility. From December 1998 through December 31, 2001, we purchased shares representing an additional 28 percent equity interest not subject to any sale or transfer restrictions. On April 12, 2002, we concluded the Arctic Gas Sale and transferred our 68 percent equity interest to the buyer. The equity earnings of Arctic Gas have historically been based on a calendar year ended September 30. The fourth quarter of 2001, the first quarter of 2002 and the first twelve days of April have been included in the results for 2002.

We account for our interest in Arctic Gas using the equity method due to the significant influence we exercise over the operating and financial policies of Arctic Gas. Our weighted-average equity interest, not subject to any sale or transfer restrictions for the years ended December 31, 2002, 2001 and 2000 was 49 percent, 39 percent and 29 percent, respectively. We recorded as our share in the losses of Arctic Gas \$1.5 million, \$1.1 million and \$0.7 million for the period ended April 12, 2002 and September 30, 2001, and 2000, respectively. Certain provisions of Russian corporate law would effectively require minority shareholder consent to enter into new agreements between us and Arctic Gas, or change any terms in any existing agreements between the two partners such as the Cooperation Agreement and the Share Disposition Agreement, including the conditions upon which the restrictions on the shares could be removed. Arctic Gas began selling oil in June 2000. Summarized financial information for Arctic Gas follows (in thousands). All amounts represent 100 percent of Arctic Gas.

Year ended September 30:	2002	2001	2000
Revenues			
Oil Sales	$ 7,880	$ 13,374	$ 3,354
Expenses			
Selling and distribution expenses	3,170	3,867	-
Operating expense	2,473	3,483	1,004
Depletion, depreciation and amortization	333	1,032	432
General and administrative	2,112	3,025	2,154
Taxes other than on income	1,261	3,881	1,422
	9,349	15,288	5,012
Loss from operations	(1,469)	(1,914)	(1,658)
Other non-operating income (expense)			
Other income (expense)	(4)	54	(14)
Interest and foreign exchange expense	(1,722)	(1,848)	(1,558)
	(1,726)	(1,794)	(1,572)
Loss before income taxes	(3,195)	(3,708)	(3,230)
Income tax expense	-	-	188
Net loss	$ (3,195)	$ (3,708)	$ (3,418)

At September 30:	2001	2000
Current assets	$ 4,423	$ 1,205
Other assets	14,986	10,120
Current liabilities	35,658	23,955
Net (deficit)	(16,249)	(12,630)

Note 10 - Venezuela Operations

On July 31, 1992, we and our partner, Venezolana de Inversiones y Construcciones Clerico, C.A. ("Vinccler"), signed an operating service agreement to reactivate and further develop three Venezuelan oil fields with Lagoven, S.A., then one of three exploration and production affiliates of the national oil company, PDVSA. The operating service agreement covers the Uracoa, Bombal and Tucupita Fields that comprise the South Monagas Unit. Under the terms of the operating service agreement, Benton-Vinccler, a Venezuelan corporation owned 80 percent by us and 20 percent by Vinccler, is a contractor for PDVSA and is responsible for overall operations of the South Monagas Unit, including all necessary investments to reactivate and develop the fields comprising the South Monagas Unit. Benton-Vinccler receives an operating fee in U.S. dollars deposited into a U.S. commercial bank account for each barrel of crude oil produced (subject to periodic adjustments to reflect changes in a special energy index of the U.S. Consumer Price Index) and is reimbursed according to a prescribed formula in U.S. dollars for its capital costs, provided that such operating fee and cost recovery fee cannot exceed the maximum dollar amount per barrel set forth in the agreement.

On September 19, 2002, Benton-Vinccler and PDVSA signed an amendment to the operating service agreement, providing for the delivery of up to 198 Bcf of natural gas through July 2012 at a price of $1.03 per Mcf. Natural gas sales are expected to commence at a rate of 40 to 50 MMcf of natural gas per day in the fourth quarter of 2003 and gradually increase up to 70 MMcfpd in 12 to 18 months from the initial sale. In addition, Benton-Vinccler agreed to sell to PDVSA 4.5 million barrels of oil at $7.00 per barrel beginning with our first gas sale. Initial gas production will come from Uracoa, which allows us to more efficiently manage the reservoir and eliminate the restrictions on producing oil wells with high gas to oil ratios. The gas reserves in Bombal will be used to meet the future terms of the gas contract in 2005 or 2006.

The Venezuelan government maintains full ownership of all hydrocarbons in the fields.

We drilled eleven oil and two water injection wells in 2002.

Note 11 - United States Operations

We had a 35 percent working interest in the Lakeside Exploration Prospect, Cameron Parish, Louisiana. In September 2002, we determined that the Claude Boudreaux #1 exploratory well was not prospective for hydrocarbons and assigned our entire interest in the Lakeside Exploration Prospect to a third party. We recognized $1.1 million impairment in the three months ended September 30, 2002.

We acquired a 100 percent interest in three California State offshore oil and gas leases ("California Leases") and a parcel of onshore property from Molino Energy Company, LLC. We impaired all of the capitalized costs associated with the California Leases of $9.2 million and the joint interest receivable of $3.1 million due from Molino Energy at December 31, 1999. The Company has determined that it will not pursue further development of the California Leases, and will plug and abandon the previously drilled exploratory well, and undertake any required lease and land reclamation. It is believed that these costs will not be material.

Note 12 - China Operations

In December 1996, we acquired Crestone Energy Corporation, subsequently renamed Benton Offshore China Company. Its principal asset is a petroleum contract with China National Offshore Oil Corporation ("CNOOC") for the WAB-21 area. The WAB-21 petroleum contract covers 6.2 million acres in the South China Sea, with an option for an additional 1.25 million acres under certain circumstances, and lies within an area which is the subject of a territorial dispute between the People's Republic of China and Vietnam. Vietnam has executed an agreement on a portion of the same offshore acreage with another company. The territorial dispute has lasted for many years, and there has been limited exploration and no development activity in the area under dispute. As part of our review of company assets, we conducted a third-party evaluation of the WAB-21 area. Through that evaluation and our own assessment we recorded a $13.4 million impairment charge in the second quarter of 2002. WAB-21 represents the $2.9 million excluded from the full cost pool as reflected on our December 31, 2002 balance sheet.

Note 13 - Related Party Transactions

From 1996 through 1998, we made unsecured loans to our then Chief Executive Officer, A. E. Benton, bearing interest at the rate of 6 percent per annum. We subsequently obtained a security interest in Mr. Benton's shares of our stock and stock options. In August 1999, Mr. Benton filed a chapter 11 (reorganization) bankruptcy petition in the U.S. Bankruptcy Court for the Central District of California, in Santa Barbara, California. In February 2000, we entered into a separation agreement with Mr. Benton pursuant to which we retained Mr. Benton under a consulting agreement to perform certain services for us. In addition, the consulting agreement provided Mr. Benton with incentive bonuses tied to our net cash receipts from the sale of our interests in Arctic Gas and Geoilbent. We paid Mr. Benton a total of $536,545 from February 2000 through May 2001 for services performed under the consulting agreement, and in June 2002, we made an estimated incentive bonus payment to Mr. Benton of $1.5 million in connection with the Arctic Gas Sale which we recorded as a reduction of the gain on the Arctic Gas Sale.

On May 11, 2001, Mr. Benton and the Company entered into a settlement and release agreement under which the consulting agreement was terminated as to future services and Mr. Benton agreed to propose a plan of reorganization in his bankruptcy case that provides for the repayment of our loans to him. In March 2002, Mr. Benton filed a plan of reorganization in his bankruptcy case which incorporated the terms of the settlement agreement. On July 31, 2002, the bankruptcy court confirmed the plan of reorganization, and the order to become final on August 10, 2002. As of that date, Mr. Benton's indebtedness was about $6.7 million for which we provided a full reserve. On August 14, 2002, we exercised our rights with respect to 600,000 shares of stock in the Company pledged to repayment of the loan and took the shares into the Company as treasury stock. Based on a $3.56 closing price for the stock on that date, the value of the shares was $2.1 million. Also, in September 2002, we received a payment of about $1.1 million as a partial distribution from Mr. Benton's debtor-in-possession account. Finally, under the terms of the settlement agreement, we have retained about $0.1 million from the Arctic Gas bonus payment to Mr. Benton for a total recovery of $3.3 million. We continue to accrue interest and provide a reserve on the remaining amount due. About $960,000 remains in the debtor-in-possession account which Mr. Benton has withheld to cover expenses and estimated tax liability for the 600,000 shares of stock we acquired from Mr. Benton. We are due the balance of this account as the expenses and tax liabilities are finally determined. We also hold the rights to direct the exercise of Mr. Benton's stock options.

Mr. Benton and the Company disagree over Mr. Benton's remaining obligations to us under the settlement agreement and plan of reorganization. In addition, Mr. Benton is claiming that he is due significant additional amounts with respect to the incentive bonus associated with the Arctic Gas Sale. Mr. Benton and the Company have agreed to submit their dispute to binding arbitration. While the outcome of arbitration cannot be predicted, we believe that we have a substantial basis for our positions and intend to vigorously pursue them.

Note 14 - Earnings Per Share

Basic earnings per common share ("EPS") is computed by dividing income available to common stockholders by the weighted-average number of common shares outstanding for the period. The weighted average number of common shares outstanding for computing basic EPS was 34.6 million, 34.0 million and 30.7 million for the years ended December 31, 2002, 2001 and 2000, respectively. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. The weighted average number of common shares outstanding for computing diluted EPS, including dilutive stock options, was 36.1 million, 34.0 million and 30.9 million for the years ended December 31, 2002, 2001 and 2000, respectively.

An aggregate of 3.5 million options and warrants were excluded from the earnings per share calculations because their exercise price exceeded the average share price during the year ended December 31, 2002. For the years ended December 31, 2001 and 2000, 6.7 million and 5.6 million options and warrants, respectively, were excluded from the earnings per share calculations because they were anti-dilutive.

Note 15 – Subsequent Event

Benton-Vinccler has hedged a portion of its 2003 oil sales by purchasing a WTI crude oil "put" to protect its 2003 cash flow. The put is for 10,000 barrels of oil per day for the period of March 1, 2003 through December 31, 2003. Due to the pricing structure for our Venezuela oil, the put has the economic effect of hedging approximately 20,000 Bopd. The put costing $2.50 per barrel, or approximately $7.7 million, has a strike price of $30.00 per barrel.

HARVEST NATURAL RESOURCES, INC. AND SUBSIDIARIES

Quarterly Financial Data (unaudited)

Summarized quarterly financial data is as follows:

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(amounts in thousands, except per share data)			
Year ended December 31, 2002				
Revenues	$ 27,247	$ 33,022	$ 38,841	$ 27,621
Expenses	(18,720)	(35,747)	(17,914)	(19,765)
Non-operating income (expense)	(3,948)	142,940	(818)	(2,948)
Income (loss) from consolidated companies before income taxes and minority interests	4,579	140,215	20,109	4,908
Income tax expense (benefit)	1,801	59,692	6,612	(7,810)
Income (loss) before minority interests	2,778	80,523	13,497	12,718
Minority interests	1,380	2,031	2,590	3,318
Income (loss) from consolidated companies	1,398	78,492	10,907	9,400
Equity in earnings (loss) of affiliated companies	87	(2,172)	1,209	1,041
Net income (loss)	$ 1,485	$ 76,320	$ 12,116	$ 10,441
Other comprehensive loss	—	—	(658)	—
Total comprehensive income	$ 1,485	$ 76,320	$ 11,458	$ 9,791
Net income (loss) per common share:				
Basic	$ 0.04	$ 2.20	$ 0.35	$ 0.30
Diluted	$ 0.04	$ 2.10	$ 0.33	$ 0.28

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(amounts in thousands, except per share data)			
Year ended December 31, 2001				
Revenues	$ 34,338	$ 32,844	$ 31,370	$ 23,834
Expenses	(24,674)	(24,493)	(22,345)	(22,673)
Non-operating expense	(5,304)	(5,152)	(5,119)	(5,444)
Income (loss) from consolidated companies before income taxes and minority interests	4,360	3,199	3,906	(4,283)
Income tax expense (benefit)	3,196	3,881	3,510	(46,285)
Income (loss) before minority interests	1,164	(682)	396	42,002
Minority interests	1,293	1,541	1,523	1,188
Income (loss) from consolidated companies	(129)	(2,223)	(1,127)	40,814
Equity in earnings (loss) of affiliated companies	2,414	1,061	2,859	(432)
Net income (loss)	$ 2,285	$ (1,162)	$ 1,732	$ 40,382
Net income (loss) per common share:				
Basic and Diluted	$ 0.07	$ (0.03)	$ 0.05	$ 1.19

In the second quarter of 2002, we recognized in non-operating income, the $140.2 million pre-tax gain on the Arctic Gas Sale, and in expense, the write-down of capitalized costs of $13.4 million associated with our WAB-21 offshore China concession.

In the fourth quarter of 2001, we recognized a $50.4 million tax benefit related to the expected utilization by the Arctic Gas Sale in 2002.

Supplemental Information on Oil and Natural Gas Producing Activities (unaudited)

In accordance with Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities" ("SFAS 69"), this section provides supplemental information on our oil and natural gas exploration and production activities. Tables I through III provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables IV through VI present information on our estimated proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves, and changes in estimated discounted future net cash flows.

TABLE I - Total costs incurred in oil and natural gas acquisition, exploration and development activities (in thousands):

	Venezuela	China	United States and Other	Total
Year Ended December 31, 2002				
Development costs	$ 49,163	$ 120	$ 577	$ 49,860
Exploration costs	794	(149)	88	733
	$ 49,957	$ (29)	$ 665	$ 50,593
Year Ended December 31, 2001				
Development costs	$ 35,194	$ 77	$ 28	$ 35,299
Exploration costs	7,694	-	909	8,603
	$ 42,888	$ 77	$ 937	$ 43,902
Year Ended December 31, 2000				
Acquisition costs	$ -	$ -	$ 170	$ 170
Development costs	47,604	-	-	47,604
Exploration costs	94	84	2,470	2,648
	$ 47,698	$ 84	$ 2,640	$ 50,422

TABLE II - Capitalized costs related to oil and natural gas producing activities (in thousands):

	Venezuela	China	United States and Other	Total
December 31, 2002				
Proved property costs	$ 519,175	$ 26,210	$ 21,030	$ 566,415
Costs excluded from amortization	—	2,900	—	2,900
Oilfield inventories	7,286	—	—	7,286
Less accumulated depletion and impairment	(386,824)	(26,210)	(20,764)	(433,798)
	$ 139,637	$ 2,900	$ 266	$ 142,803
December 31, 2001				
Proved property costs	$ 469,218	$ 12,892	$ 19,813	$ 501,923
Costs excluded from amortization	-	16,248	560	16,808
Oilfield inventories	15,219	-	-	15,219
Less accumulated depletion and impairment	(361,313)	(12,892)	(19,544)	(393,749)
	$ 123,124	$ 16,248	$ 829	$ 140,201
December 31, 2000				
Proved property costs	$ 426,330	$ 12,879	$ 19,362	$ 458,571
Costs excluded from amortization	-	16,183	451	16,634
Oilfield inventories	15,343	-	-	15,343
Less accumulated depletion and impairment	(339,542)	(12,879)	(19,090)	(371,511)
	$ 102,131	$ 16,183	$ 723	$ 119,037

TABLE III - Results of operations for oil and natural gas producing activities (in thousands):

	Venezuela	China	United States and Other	Total
Year ended December 31, 2002				
Oil sales	$ 126,731	$ —	$ —	$ 126,731
Expenses:				
Operating, selling and distribution expenses and taxes other than on income	31,608	2,493	—	34,101
Write-down of oil and gas properties and impairments	—	13,371	1,166	14,537
Depletion	24,941	—	—	24,941
Income tax expense	4,715	3	—	4,718
Total expenses	61,264	15,867	1,166	78,297
Results of operations from oil and natural gas producing activities	$ 65,467	$ (15,867)	$ (1,166)	$ 48,434
Year ended December 31, 2001				
Oil sales	$ 122,386	$ —	$ —	$ 122,386
Expenses:				
Operating, selling and distribution expenses and taxes other than on income	42,212	—	722	42,934
Write-down of oil and gas properties and impairments	-	13	455	468
Depletion	22,119	—	—	22,119
Income tax expense	11,156	—	13	11,169
Total expenses	75,487	13	1,190	76,690
Results of operations from oil and natural gas producing activities	$ 46,899	$ (13)	$ (1,190)	$ 45,696
Year ended December 31, 2000				
Oil and natural gas sales	$ 139,890	$ —	$ 394	$ 140,284
Expenses:				
Operating, selling and distribution expenses and taxes other than on income	46,879	—	731	47,610
Write-down of oil and gas properties and impairments	—	8	1,338	1,346
Depletion	15,331	—	45	15,376
Income tax expense	20,398	—	12	20,410
Total expenses	82,608	8	2,126	84,742
Results of operations from oil and natural gas producing activities	$ 57,282	$ (8)	$ (1,732)	$ 55,542

TABLE IV - Quantities of Oil and Natural Gas Reserves

Proved reserves are estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those which are expected to be recovered through existing wells with existing equipment and operating methods. All Venezuelan reserves are attributable to an operating service agreement between Benton-Vinccler and PDVSA, under which all mineral rights are owned by the government of Venezuela. Venezuelan reserves include production projected through the end of the operating service agreement in July 2012.

The Securities and Exchange Commission requires the reserve presentation to be calculated using year-end prices and costs and assuming a continuation of existing economic conditions. Proved reserves cannot be measured exactly, and the estimation of reserves involves judgmental determinations. Reserve estimates must be reviewed and adjusted periodically to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes. The estimates are based on current technology and economic conditions, and we consider such estimates to be reasonable and consistent with current knowledge of the characteristics and extent of production. The estimates include only those amounts considered to be Proved Reserves and do not include additional amounts which may result from new discoveries in the future, or from application of secondary and tertiary recovery processes where facilities are not in place or for which transportation and/or marketing contracts are not in place.

Proved Developed Reserves are reserves which can be expected to be recovered through existing wells with existing equipment and existing operating methods. This classification includes: a) proved developed producing reserves which are reserves expected to be recovered through existing completion intervals now open for production in existing wells; and b) proved developed nonproducing reserves which are reserves that exist behind the casing of existing wells which are expected to be produced in the predictable future, where the cost of making such oil and natural gas available for production should be relatively small compared to the cost of a new well.

Any reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing primary recovery methods are included as Proved Developed Reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves are Proved Reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled. Estimates of recoverable reserves for proved undeveloped reserves may be subject to substantial variation and actual recoveries may vary materially from estimates.

Proved Reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. No estimates for Proved Undeveloped Reserves are attributable to or included in this table for any acreage for which an application of fluid injection or other improved recovery technique is contemplated unless proved effective by actual tests in the area and in the same reservoir.

Changes in previous estimates of proved reserves result from new information obtained from production history and changes in economic factors.

The evaluations of the oil and natural gas reserves as of December 31, 2002, 2001 and 2000 were prepared by Ryder Scott Company L.P., independent petroleum engineers.

The tables shown below represent our interests in the United Sates and Venezuela in each of the years. In addition to these reserves is our 34 percent interest in Geoilbent which combined with our United States and Venezuela crude oil, condensate and natural gas liquids reserves, represent our net interest in all reserves as of December 31, 2002.

	United States	Venezuela	Minority Interest in Venezuela	Net Total
Proved Reserves-Crude oil, condensate, and natural gas liquids (MBbls)				
Year ended December 31, 2002				
Proved reserves beginning of the year	—	104,514	(20,903)	83,611
Revisions of previous estimates	—	362	(72)	290
Extensions, discoveries and improved recovery	—	—	—	—
Production	—	(9,708)	1,942	(7,766)
Sales of reserves in place	—	—	—	—
Proved reserves at end of the year	—	95,168	(19,033)	76,135
Russia – Geoilbent (34%) Proved reserves at end of the year				24,781
Year ended December 31, 2001				
Proved reserves beginning of the year	—	123,039	(24,608)	98,431
Revisions of previous estimates	—	(8,747)	1,749	(6,998)
Extensions, discoveries and improved recovery	—	—	—	—
Production	—	(9,778)	1,956	(7,822)
Sales of reserves in place	—	—	—	—
Proved reserves at end of the year	—	104,514	(20,903)	83,611
Russia – Arctic Gas (39%) Proved reserves at end of the year				20,964
Russia – Geoilbent (34%) Proved reserves at end of the year				29,668
Year ended December 31, 2000				
Proved reserves at beginning of the year	—	134,961	(26,992)	107,969
Revisions of previous estimates	—	(8,826)	1,765	(7,061)
Purchases of reserves in place	15	—	—	15
Extensions, discoveries and improved recovery	—	6,268	(1,254)	5,014
Production	(7)	(9,364)	1,873	(7,498)
Sales of reserves in place	(8)	—	—	(8)
Proved reserves at end of the year	—	123,039	(24,608)	98,431
Russia – Arctic Gas (29%) Proved reserves at end of the year				15,821
Russia – Geoilbent (34%) Proved reserves at end of the year				32,614
Proved Developed Reserves at:				
December 31, 2002	—	53,833	(10,767)	43,066
December 31, 2001	—	51,465	(10,293)	41,172
December 31, 2000	—	67,217	(13,443)	53,774
Russia – Arctic Gas Proved reserves at end of the year				
2001 (39%)				2,483
2000 (29%)				2,325
Russia – Geoilbent (34%) Proved reserves at end of the year				
2002				11,840
2001				15,658
2000				14,913
Proved reserves-natural gas (MMcf)				
Year ended December 31, 2002				
Proved reserves beginning of the year	—	—	—	—
Revisions of previous estimates	—	—	—	—
Extensions, discoveries and improved recovery	—	198,000	(39,600)	158,400
Sales of reserves in place	—	—	—	—
Proved reserves end of the year		198,000	(39,600)	158,400
Russia – Arctic Gas (39%) Proved reserves – December 31, 2001				208,010
Russia – Arctic Gas (39%) Proved reserves – December 31, 2000				152,496
Proved Developed Reserves at:				
December 31, 2002	—	105,000	(21,000)	84,000
Russia – Arctic Gas				
2001 (39%)				21,292
2000 (29%)				17,801

TABLE V - Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Natural Gas Reserve Quantities

The standardized measure of discounted future net cash flows is presented in accordance with the provisions of SFAS 69. In preparing this data, assumptions and estimates have been used, and we caution against viewing this information as a forecast of future economic conditions.

Future cash inflows were estimated by applying year-end prices, adjusted for fixed and determinable escalations provided by contract, to the estimated future production of year-end proved reserves. Future cash inflows were reduced by estimated future production and development costs to determine pre-tax cash inflows. Future income taxes were estimated by applying the year-end statutory tax rates to the future pre-tax cash inflows, less the tax basis of the properties involved, and adjusted for permanent differences and tax credits and allowances. The resultant future net cash inflows are discounted using a ten percent discount rate.

The tables shown below represent our interest Venezuela in each of the years. In addition to these reserves is our 34 percent interest in Geoilbent and our Arctic Gas interest of 39% and 29% at December 31, 2001 and 2000, respectively. Which combined with our Venezuela crude oil, condensate and natural gas liquids reserves represent our net interest in all reserves as of December 31, 2002. Geoilbent's Russian domestic crude oil price declined significantly for the period from September 30, 2002 until December 31, 2002. The standardized measure of discounted future net cash flows declined from $92.9 million to $41.5 million. There was a $5.05 per barrel decline in the value of a barrel between these two periods. The reserves in place and development cost structure were approximately the same. The lower prices at December 31, 2002 were offset by lower royalties, production taxes, export fees and income taxes. The Russian domestic crude oil price declined from approximately $9.50 to $5.00 per barrel by December 31. While world crude oil prices and Russian export prices increased from approximately $20 to $29. Geoilbent sells approximately 66 percent of its crude oil sales into the Russian domestic market. Geoilbent's production is currently limited to shipments on the Transneft crude oil pipeline system. This system suffers from winter export limitations. Geoilbent reports its standardized measure of discounted future net cash flows at September 30. The Company reports the results of Ryder Scott Company L.P. independent engineering evaluation at December 31 to provide comparability with its Venezuelan reserves. Geoilbent's 34 percent interest declined by $51.4 million as measured by the December 31, 2002 year-end weighted average price. We do not believe that the year-end prices are indicative of the value of Geoilbent. *See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.*

	Venezuela	Minority Interest in Venezuela	Net Total
		(amounts in thousands)	
December 31, 2002			
Future cash inflow	$ 1,510,346	$ (302,069)	$ 1,208,277
Future production costs	(400,694)	80,139	(320,555)
Future development costs	(192,671)	38,534	(154,137)
Future net revenue before income taxes	916,981	(183,396)	733,585
10% annual discount for estimated timing of cash flows	(315,376)	63,075	(252,301)
Discounted future net cash flows before income taxes	601,605	(120,321)	481,284
Future income taxes, discounted at 10% per annum	(204,356)	40,871	(163,485)
Standardized measure of discounted future net cash flows	$ 397,249	$ (79,450)	$ 317,799
Russia – Geoilbent (34%)			$ 45,395

December 31, 2001			
Future cash flows	$ 1,030,404	$ (206,081)	$ 824,323
Future production costs	(558,431)	111,686	(446,745)
Future development costs	(142,006)	28,401	(113,605)
Future net revenue before income taxes	329,967	(65,994)	263,973
10% annual discount for estimated timing of cash flows	(109,704)	21,941	(87,763)
Discounted future net cash flows before income taxes	220,263	(44,053)	176,210
Future income taxes, discounted at 10% per annum	(16,103)	3,221	(12,882)
Standardized measure of discounted future net cash flows	$ 204,160	$ (40,832)	$ 163,328
Russia – Arctic Gas (29%)			$ 82,205
Russia – Geoilbent (34%)			$ 70,648
December 31, 2000			
Future cash inflow	$ 1,505,870	$ (301,174)	$ 1,204,696
Future production costs	(618,870)	123,774	(495,096)
Future development costs	(166,039)	33,208	(132,831)
Future net revenue before income taxes	720,961	(144,192)	576,769
10% annual discount for estimated timing of cash flows	(260,381)	52,076	(208,305)
Discounted future net cash flows before income taxes	460,580	(92,116)	368,464
Future income taxes, discounted at 10% per annum	(104,894)	20,979	(83,915)
Standardized measure of discounted future net cash flows	$ 355,686	$ (71,137)	$ 284,549
Russia – Arctic Gas (29%)			$ 56,880
Russia – Geoilbent (34%)			$ 114,725

TABLE VI - Changes in the Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

	Net Venezuela		
	2002	**2001**	**2000**
	(amounts in thousands)		
Present Value at January 1	$ 163,328	$ 284,549	$ 380,865
Sales of oil and natural gas, net of related costs	(76,098)	(64,139)	(58,913)
Revisions to estimates of proved reserves			
Net changes in prices, development and production costs	310,043	(141,429)	(124,402)
Quantities	611	(26,198)	(26,494)
Extensions, discoveries and improved recovery, net of future costs	89,670	—	16,429
Accretion of discount	17,621	36,846	52,135
Net change in income taxes	(150,603)	71,033	56,567
Development costs incurred	40,532	23,768	36,210
Changes in timing and other	(77,305)	(21,102)	(47,848)
Present Value at December 31	$ 317,799	$ 163,328	$ 284,549

Additional Supplemental Information on Oil and Natural Gas Producing Activities (unaudited)
for Russia Equity Affiliates as of September 30, their fiscal year end.

In accordance with Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities" ("SFAS 69"), this section provides supplemental information on our oil and natural gas exploration and production activities. Tables I through III provide historical cost information pertaining to costs incurred in exploration, property acquisitions and development; capitalized costs; and results of operations. Tables IV through VI present information on our estimated proved reserve quantities, standardized measure of estimated discounted future net cash flows related to proved reserves, and changes in estimated discounted future net cash flows.

Geoilbent (34 percent ownership by us) and Arctic Gas (39 percent and 29 percent ownership not subject to certain sale and transfer restrictions at December 31, 2002 and 2001, until Arctic Gas was sold on April 12, 2002, respectively), which are accounted for under the equity method, have been included at their respective ownership interests in the consolidated financial statements based on a fiscal period ending September 30 and, accordingly, results of operations for oil and natural gas producing activities in Russia reflect the years ended September 30, 2002, 2001, and 2000.

TABLE I - Total costs incurred in oil and natural gas acquisition, exploration and development activities (in thousands):

	Arctic Gas	Geoilbent	Total Equity Affiliates
Year Ended September 30, 2002			
Development costs	$ —	$ 8,501	$ 8,501
Exploration costs	16,156	498	16,654
	$ 16,156	$ 8,999	$ 25,155
Year Ended September 30, 2001			
Development costs	$ —	$ 11,418	$ 11,418
Exploration costs	8,136	2,074	10,210
	$ 8,136	$ 13,492	$ 21,628
Year Ended September 30, 2000			
Development costs	$ —	$ 13,290	$ 13,290
Exploration costs	4,206	279	4,485
	$ 4,206	$ 13,569	$ 17,775

TABLE II - Capitalized costs related to oil and natural gas producing activities (in thousands):

	Arctic Gas	Geoilbent	Total Equity Affiliates
September 30, 2002			
Proved property costs	$ —	$ 94,404	$ 94,404
Costs excluded from amortization	—	272	272
Oilfield inventories	—	2,348	2,348
Less accumulated depletion and impairment	—	(31,440)	(31,440)
	$ —	$ 65,584	$ 65,584
September 30, 2001			
Proved property costs	$ 5,786	$ 85,677	$ 91,463
Costs excluded from amortization	11,549	—	11,549
Oilfield inventories	175	4,357	4,532
Less accumulated depletion and impairment	(389)	(22,203)	(22,592)
	$ 17,121	$ 67,831	$ 84,952
September 30, 2000			
Proved property costs	$ 12,901	$ 72,184	$ 85,085
Costs excluded from amortization	6,536	—	6,536
Oilfield inventories	—	2,705	2,705
Less accumulated depletion and impairment	(78)	(17,130)	(17,208)
	$ 19,359	$ 57,759	$ 77,118

TABLE III - Results of operations for oil and natural gas producing activities (in thousands):

	Arctic Gas	Geoilbent	Total Equity Affiliates
Year ended December 31, 2002			
Oil sales	$ 3,554	$ 31,039	$ 34,593
Expenses:			
Operating, selling and distribution expenses and taxes other than on income	3,102	16,902	20,004
Depletion	139	9,237	9,376
Income tax expense	19	1,955	1,974
Total expenses	3,260	28,094	31,354
Results of operations from oil and natural gas producing activities	$ 294	$ 2,945	$ 3,239
Year ended December 31, 2001			
Oil sales	$ 4,016	$ 34,261	$ 38,277
Expenses:			
Operating, selling and distribution expenses and taxes other than on income	3,381	16,083	19,464
Depletion	311	5,072	5,383
Income tax expense	80	3,742	3,822
Total expenses	3,772	24,897	28,669
Results of operations from oil and natural gas producing activities	$ 244	$ 9,364	$ 9,608
Year ended December 31, 2000			
Oil sales	$ 889	$ 26,716	$ 27,605
Expenses:			
Operating, selling and distribution expenses and taxes other than on income	604	10,831	11,435
Depletion	78	3,249	3,327
Income tax expense	54	3,306	3,360
Total expenses	736	17,386	18,122
Results of operations from oil and natural gas producing activities	$ 153	$ 9,330	$ 9,483

TABLE IV - Quantities of Oil and Natural Gas Reserves

Proved reserves are estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are those which are expected to be recovered through existing wells with existing equipment and operating methods. Geoilbent and Arctic Gas oil and gas fields are situated on land belonging to the Government of the Russian Federation. Each obtained licenses from the local authorities and pays unified production taxes to explore and produce oil and gas from these fields. Geoilbent's licenses will expire in September 2018 the license expiration for the North Gubkinskoye field, and in March 2023 for the South Tarasovskoye field. However, under Paragraph 4 of the Russian Federal Law 20-FZ, dated January 2, 2000, the license may be extended over the economic life of the lease at Geoilbent's option. Geoilbent intends to extend such licenses for properties that are expected to produce subsequent to their expiry dates. Estimates of proved reserves extending past the license expiration represent approximately 5 percent of total proved reserves. Arctic Gas had licenses to develop the Samburg and Yevo-Yakhinskiy fields in western Siberia. Arctic Gas was sold on April 12, 2002.

The Securities and Exchange Commission requires the reserve presentation to be calculated using year-end prices and costs and assuming a continuation of existing economic conditions. Proved reserves cannot be measured exactly, and the estimation of reserves involves judgmental determinations. Reserve estimates must be reviewed and adjusted periodically to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes. The estimates are based on current technology and economic conditions, and we consider such estimates to be reasonable and consistent with current knowledge of the characteristics and extent of production. The estimates include only those amounts considered to be Proved Reserves and do not include additional amounts which may result from new discoveries in the future, or from application of secondary and tertiary recovery processes where facilities are not in place or for which transportation and/or marketing contracts are not in place.

Proved Developed Reserves are reserves which can be expected to be recovered through existing wells with existing equipment and existing operating methods. This classification includes: a) proved developed producing reserves which are reserves expected to be recovered through existing completion intervals now open for production in existing wells; and b) proved developed nonproducing reserves which are reserves that exist behind the casing of existing wells which are expected to be produced in the predictable future, where the cost of making such oil and natural gas available for production should be relatively small compared to the cost of a new well.

Any reserves expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing primary recovery methods are included as Proved Developed Reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Proved Undeveloped Reserves are Proved Reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units, which are reasonably certain of production when drilled. Estimates of recoverable reserves for proved undeveloped reserves may be subject to substantial variation and actual recoveries may vary materially from estimates.

Proved Reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. No estimates for Proved Undeveloped Reserves are attributable to or included in this table for any acreage for which an application of fluid injection or other improved recovery technique is contemplated unless proved effective by actual tests in the area and in the same reservoir.

Changes in previous estimates of proved reserves result from new information obtained from production history and changes in economic factors.

	Arctic Gas	Geoilbent	Total Equity Affiliates
Proved Reserves-Crude oil, condensate, and natural gas liquids (MBbls)			
Year ended September 30, 2002			
Proved reserves beginning of the year	20,965	29,668	50,633
Revisions of previous estimates	—	(3,455)	(3,455)
Extensions, discoveries and improved recovery	—	1,493	1,493
Production	(89)	(2,350)	(2,439)
Sales of reserves in place	(20,876)	—	(20,876)
Proved reserves at end of the year	—	25,356	25,356
Year ended September 30, 2001			
Proved reserves beginning of the year	15,821	32,614	48,435
Revisions of previous estimates	5,327	(5,594)	(267)
Extensions, discoveries and improved recovery	—	4,411	4,411
Production	(183)	(1,763)	(1,946)
Sales of reserves in place	—	—	—
Proved reserves at end of the year	20,965	29,668	50,633
Year ended September 30, 2000			
Proved reserves beginning of the year	3,715	36,414	40,129
Revisions of previous estimates	4,093	(6,904)	(2,811)
Extensions, discoveries and improved recovery	8,062	4,548	12,610
Production	(49)	(1,444)	(1,493)
Sales of reserves in place	—	—	—
Proved reserves at end of the year	15,821	32,614	48,435
Proved Developed Reserves at:			
September 30, 2002	—	11,840	11,840
September 30, 2001	2,483	15,658	18,141
September 30, 2000	2,325	14,913	17,238

Proved reserves-natural gas (MMcf)			
Year ended September 30, 2002			
Proved reserves beginning of the year	208,010	—	208,010
Revisions of previous estimates	—	—	—
Extensions, discoveries and improved recovery	—	—	—
Production	—	—	—
Sales of reserves in place	(208,010)	—	(208,010)
Proved reserves end of the year	—	—	—
Year ended September 30, 2001			
Proved reserves beginning of the year	152,496	—	152,496
Revisions of previous estimates	55,514	—	55,514
Extensions, discoveries and improved recovery	—	—	—
Production	—	—	—
Sales of reserves in place	—	—	—
Proved reserves end of the year	208,010	—	208,010
Year ended September 30, 2000			
Proved reserves beginning of the year	—	—	—
Revisions of previous estimates	—	—	—
Extensions, discoveries and improved recovery	152,496	—	152,496
Production	—	—	—
Sales of reserves in place	—	—	—
Proved reserves end of the year	152,496	—	152,496
Proved Developed Reserves at:			
September 30, 2002	—	—	—
September 30, 2001	21,292	—	21,292
September 30, 2000	17,801	—	17,801

TABLE V - Standardized Measure of Discounted Future Net Cash Flows Related to Proved Oil and Natural Gas Reserve Quantities

The standardized measure of discounted future net cash flows is presented in accordance with the provisions of SFAS 69. In preparing this data, assumptions and estimates have been used, and we caution against viewing this information as a forecast of future economic conditions.

Future cash inflows were estimated by applying year-end prices, adjusted for fixed and determinable escalations provided by contract, to the estimated future production of year-end proved reserves. Future cash inflows were reduced by estimated future production and development costs to determine pre-tax cash inflows. Future income taxes were estimated by applying the year-end statutory tax rates to the future pre-tax cash inflows, less the tax basis of the properties involved, and adjusted for permanent differences and tax credits and allowances. The resultant future net cash inflows are discounted using a ten percent discount rate.

	Arctic Gas	Geoilbent	Total Equity Affiliates
		(amounts in thousands)	
September 30, 2002			
Future cash inflow	$ —	$ 469,837	$ 469,837
Future production costs	—	(203,754)	(203,754)
Future development costs	—	(40,707)	(40,707)
Future net revenue before income taxes	—	225,376	225,376
10% annual discount for estimated timing of cash flows	—	(108,147)	(108,147)
Discounted future net cash flows before income taxes	—	117,229	117,229
Future income taxes, discounted at 10% per annum	—	(24,290)	(24,290)
Standardized measure of discounted future net cash flows	$ —	$ 92,939	$ 92,939
September 30, 2001			
Future cash inflow	$ 630,340	$ 434,348	$ 1,064,688
Future production costs	(373,458)	(251,335)	(624,793)
Future development costs	(49,139)	(37,020)	(86,159)
Future net revenue before income taxes	207,743	145,993	353,736
10% annual discount for estimated timing of cash flows	(99,343)	(64,868)	(164,211)
Discounted future net cash flows before income taxes	108,400	81,125	189,525
Future income taxes, discounted at 10% per annum	(26,195)	(10,477)	(36,672)
Standardized measure of discounted future net cash flows	$ 82,205	$ 70,648	$ 152,853
September 30, 2000			
Future cash inflow	$ 584,346	$ 688,981	$ 1,273,327
Future production costs	(395,238)	(416,440)	(811,678)
Future development costs	(36,585)	(34,035)	(70,620)
Future net revenue before income taxes	152,523	238,506	391,029
10% annual discount for estimated timing of cash flows	(78,006)	(98,346)	(176,352)
Discounted future net cash flows before income taxes	74,517	140,160	214,677
Future income taxes, discounted at 10% per annum	(17,637)	(25,435)	(43,072)
Standardized measure of discounted future net cash flows	$ 56,880	$ 114,725	$ 171,605

TABLE VI - Changes in the Standardized Measure of Discounted Future Net Cash Flows from Proved Reserves

	Equity Affiliates		
	2002	2001	2000
		(amounts in thousands)	
Present Value at October 1	$ 152,853	$ 171,605	$ 175,913
Sales of oil and natural gas, net of related costs	(23,644)	(19,001)	(20,977)
Revisions to estimates of proved reserves			
Net changes in prices, development and production costs	76,545	(39,880)	(72,740)
Quantities	(10,007)	8,881	(19,685)
Sales of reserves in place	(82,205)	—	—
Extensions, discoveries and improved recovery, net of future costs	2,031	18,767	73,542
Accretion of discount	7,065	21,468	22,359
Net change in income taxes	1,145	6,400	4,604
Development costs incurred	8,999	17,110	8,475
Changes in timing and other	(39,843)	(32,497)	114
Present Value at September 30	$ 92,939	$ 152,853	$ 171,605

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Houston, State of Texas, on the 28th day of March, 2003.

HARVEST NATURAL RESOURCES, INC.
(Registrant)

Date: March 28, 2003

By: /s/Peter J. Hill
Peter J. Hill
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed by the following persons on the 28th day of March, 2003, on behalf of the Registrant in the capacities indicated:

Signature	Title
/s/Peter J. Hill Peter J. Hill	Director, President and Chief Executive Officer
/s/Steven W. Tholen Steven W. Tholen (Principal Financial Officer)	Senior Vice President, Chief Financial Officer and Treasurer
/s/Kurt A. Nelson Kurt A. Nelson (Principal Accounting Officer)	Vice President-Controller
/s/Stephen D. Chesebro' Stephen D. Chesebro'	Chairman of the Board and Director
/s/John U. Clarke John U. Clarke	Director
/s/H.H. Hardee H.H. Hardee	Director
/s/Patrick M. Murray Patrick M. Murray	Director

I, Peter J. Hill, certify that:

1. I have reviewed this annual report on Form 10-K of Harvest Natural Resources, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: March 28, 2003

/s/ Peter J. Hill
Peter J. Hill
President and Chief Executive Officer

I, Steven W. Tholen, certify that:

1. I have reviewed this annual report on Form 10-K of Harvest Natural Resources, Inc.;

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

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

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

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

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

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

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

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

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

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

Date: March 28, 2003

/s/ Steven W. Tholen
Steven W. Tholen
Senior Vice President and
Chief Financial Officer

Accompanying Certificate
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Not Filed Pursuant to the Securities Exchange Act of 1934

The undersigned Chief Executive Officer of Harvest Natural Resources, Inc. (the "Company") do hereby certify as follows:

Solely for the purpose of meeting the apparent requirements of Section 906 of the Sarbanes-Oxley Act of 2002, and solely to the extent this certification may be applicable to this Annual Report on Form 10-K, the undersigned hereby certify that this Annual Report on Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in this Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 28, 2003

By: /s/ Peter J. Hill
Peter J. Hill
President and Chief Executive Officer

Accompanying Certificate
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Not Filed Pursuant to the Securities Exchange Act of 1934

The undersigned Chief Financial Officer of Harvest Natural Resources, Inc. (the "Company") do hereby certify as follows:

Solely for the purpose of meeting the apparent requirements of Section 906 of the Sarbanes-Oxley Act of 2002, and solely to the extent this certification may be applicable to this Annual Report on Form 10-K, the undersigned hereby certify that this Annual Report on Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in this Annual Report on Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 28, 2003

By: /s/ Steven W. Tholen
Steven W. Tholen
Senior Vice President and
Chief Financial Officer

Stock Transfer Agent & Registrar

Wells Fargo Shareowner Services
161 North Concord Exchange
South St. Paul, MN 55075
(800) 468-9716

Annual Meeting of Stockholders

May 22, 2003 at 10:00 a.m.
Holiday Inn Select
14703 Park Row
Houston, TX 77079

Investor Information

Copies of the Company's annual and quarterly reports on form 10-K and 10-Q, as filed with the Securities and Exchange Commission, are available at no charge upon written request to:

Harvest Natural Resources, Inc.
15835 Park Ten Place Drive
Suite 115
Houston, TX 77084

(281) 579-6700
(281) 579-6702 facsimile
E-mail: investorrelations@harvestnr.com

Harvest Stock

Harvest Natural Resources' stock is traded on the New York Stock Exchange (NYSE) under the symbol HNR.

Corporate Web Site

www.harvestnr.com

Designed and Produced by Pegasus Design, Inc., Houston, Texas

Harvest Natural Resources
15835 Park Ten Place Drive
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