BENTON

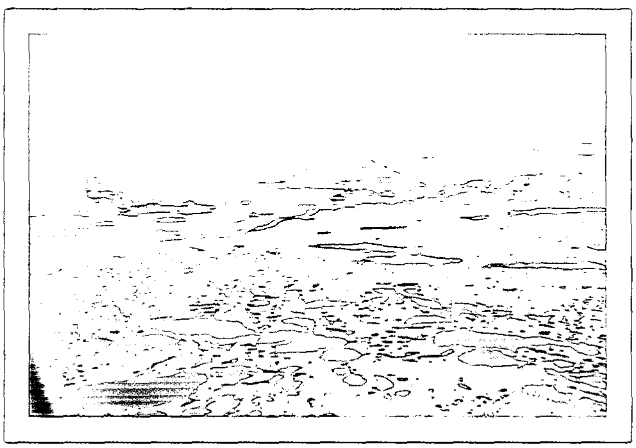
OIL AND GAS COMPANY

2001 ANNUAL REPORT

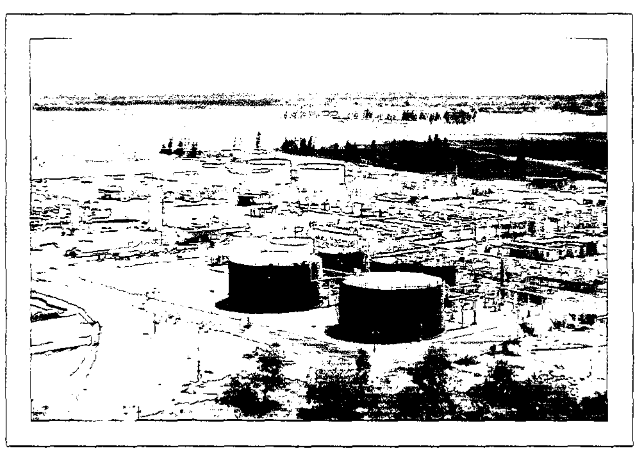
SINCE 1988, BENTON OIL AND GAS COMPANY HAS BEEN ENGAGED IN THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS PROPERTIES. THE COMPANY IS A PUBLICLY HELD, INDEPENDENT ENERGY COMPANY AND TRADES ON THE NEW YORK STOCK EXCHANGE (NYSE) UNDER THE SYMBOL BNO.

BENTON OIL AND GAS IS RECOGNIZED AS A NICHE PLAYER IN THE DEVELOPMENT OF LARGE RESOURCES OF OIL AND GAS IN AREAS OF THE WORLD THAT ARE TECHNICALLY AND POLITICALLY CHALLENGING. THE COMPANY HAS ACQUIRED WORLD CLASS PROJECTS WITH SIGNIFICANT RESERVE GROWTH POTENTIAL. HEADQUARTERED IN HOUSTON, TEXAS, THE COMPANY'S OPERATIONS ARE PRIMARILY CONDUCTED IN VENEZUELA AND RUSSIA.

PARADISE-



The barren Siberian tundra in early spring... lakes, rivers and frozen ground over a vast area.



The Benton-Vinccler plant at Uracoa in the remote grasslands of the Orinoco delta.

Financial Highlights

(Amounts in thousands, except per share)	2001	2000	1999
	Years ended December 31,		
Financial:			
Total Revenues	$122,386	$140,284	$89,060
Net Income (Loss)	43,237	20,488	(32,284)
Per Share (diluted)	1.27	0.66	(1.09)
Cash Flow from Operations (1)	28,147	47,264	6,655
Per Share (diluted)	0.83	1.53	0.23
Total Assets	348,151	286,447	276,311
Long Term Debt (2)	221,583	213,000	264,575
Stockholders' Equity	67,623	12,904	(17,178)
Average Shares Outstanding (diluted)	34,008	30,890	29,577
Operational:			
Total Production (3):			
Crude Oil and Condensate (MBbls)	9,982	8,991	9,185
Natural Gas (MMCF)	-	43	-
Oil Equivalents (MBOE)	9,982	8,998	9,185
Average Prices (4):			
Crude Oil and Condensate (per Bbl)	$12.52	$14.94	$9.21
Natural Gas (per Mcf)	-	4.63	-
Total Proved Reserves (3):			
Crude Oil and Condensate (MBbls)	134,243	146,866	148,098
Natural Gas (MMcf)	208,010	152,496	-
Oil Equivalents (MBOE)	168,911	172,282	148,098
Present Value of Reserves (3) (5)	$365,735	$583,141	$744,935

(1) Before working capital changes

(2) Net of current portion

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

(4) On sales from consolidated companies

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

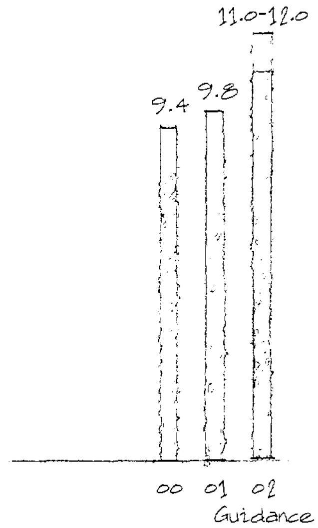
Abbreviation Guide

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

OUR JOURNEY BEGINS...

This year, our annual report resembles a journal which might have been kept by an early explorer on a journey to a promising new frontier. It documents the progress and observations of discovery in much the same manner as pioneers once did. We chose this format because we believe that our progress and success as a company is much like a journey which always advances - sometimes with ease and, at other times, requiring determination to stay the course.

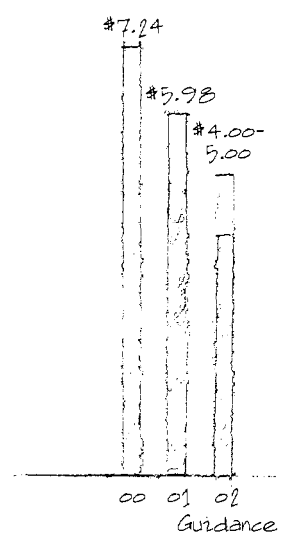
Accordingly, it is appropriate in this letter to set forth our original mission and to note the important milestones commemorating our successes, as well as noting those circumstances in which continued perseverance remains a priority.



Production is expected to increase 15% to 20% this year. (million barrels)

A JOURNEY OF PURPOSE...

Last year was the first full year for your new management team and reconstituted Board of Directors to work in a coordinated fashion to define a new shared vision for Benton and to map out our course for the future. The year was critically important to re-establishing our financial flexibility and reshaping our operating profile. We initiated a number of actions to substantially reposition our company for the future. Early in the year, we laid out two strategic priorities: first, to delever the balance sheet, thereby preserving shareholder value; and second, to improve the value of our producing assets in Venezuela and Russia. The Arctic Gas transaction, when closed, not only



Cash costs per barrel before nonrecurring charges were down $1.26 per barrel last year and could be reduced another $1.00 to $2.00 per barrel this year.

satisfies our first objective but also adds credence to our strong belief in the underlying value of our strategic assets. Underpinning the growth in the value of our producing assets was a reengineered plan for production and development in Venezuela and an aggressive attack on costs.

HARD WORK BEGINS TO PAY OFF...

After hard work by every member of the management and employee team, we announced in February 2002 that we had agreed to sell our 68 percent interest in Arctic Gas Company to a nomonize of the Yukos Oil Company, a large Russian oil and gas company, for $190 million. We will also receive approximately $30 million as repayment of intercompany loans owed to Benton by Arctic Gas.

The net proceeds we expect to realize from the sale, after expenses, taxes, and the settling of certain related claims, are estimated to be approximately $150 million. These funds will be used, in part, to retire early all of the $108 million of 11 5/8 percent senior notes which are due in 2003 in accordance with their terms and without penalty. We intend to use any remaining net proceeds and cash received from the repayment of loans to further reduce debt from time to time, accelerate our strategic growth in Venezuela and Russia, and for general corporate purposes. Retirement of all the outstanding 11 5/8 percent notes alone eliminates $12.6 million, or $0.37 per share, of annual interest expense and, most importantly for our shareholders and bondholders, removes any near-term concern about the Company's liquidity.

These retirements, plus the gain on the sale, will allow us to fulfill our earlier commitment to restore our balance sheet strength by reducing our debt-to-capitalization ratio from over 90 percent to the 45 percent range. As a result, the credit rating agencies are reviewing our credit profile.

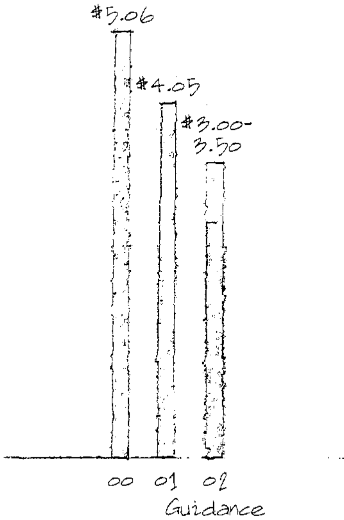
A BUMP IN THE ROAD...

Our path was not always straight, nor was it always smooth. In mid-year, we asked our bondholders effectively to modify the terms of their bonds via an exchange. The intention was to give management more time to assess the value of our asset base without the added pressure of a May 2003 maturity date for a very sizable amount of debt. In hindsight, we underestimated the Company's poor standing in the financial markets. As a result, we were unsuccessful in accomplishing this objective on economic terms which were either acceptable to us, or consistent with our goal of preserving value for our shareholders. However, in the process, we were able to achieve a modification in the terms of the bonds to allow us to borrow money, on a non-recourse basis, against the strength of our Russian assets. This was an important concession which ultimately facilitated the pending sale of our interest in Arctic Gas.

We will continue to work to improve our relationships in the capital markets by honoring our commitments and building upon a new track record of success. These efforts will help us fund the subsequent development of our assets on a cost effective, and sound, financial basis.

CARRYING A LIGHTER LOAD...

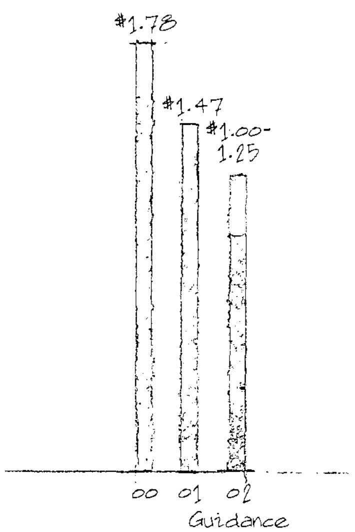
Turning to our financial and operating performance for 2001, we showed measured progress, financial discipline and the early success required to reestablish lost credibility. We met our production target of 9.8 million barrels for the year and lowered our cash expenses per barrel by approximately 18 percent to \$5.98 per barrel. The recent decline in oil prices put increased pressure on us to reduce expenses while continuing to pursue means of reducing debt and its associated interest expense. We closed the California office, reduced staff, moved to Houston and consolidated field operations "in country". This, along with the costs of the failed bond exchange, reduced our financial performance but positions us for improvement in the years ahead.



Operating expense per barrel sold before nonrecurring charges is projected to decline another 15% to 20% this year.

TRANSITION PRODUCES MIXED RESULTS...

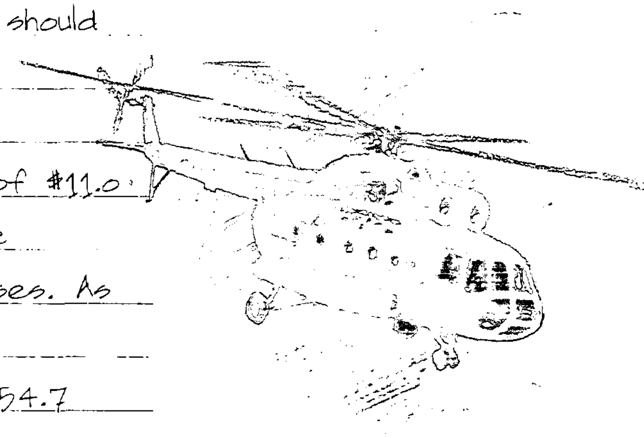
For the year, we reported recurring net income of \$8.2 million, or \$0.24 per diluted share, and discretionary cash flow of \$33.9 million, or \$1.00 per diluted share, for 2001, before certain nonrecurring items. This compares with net income of \$16.5 million, or \$0.53 per diluted share, and discretionary cash flow of \$47.3 million, or \$1.53 per diluted share in 2000. Discretionary cash flow was down in 2001 primarily due to lower oil prices and the effect of nonrecurring items, which affected both 2000 and 2001.



Restructuring the Company and moving the corporate headquarters to Houston, Texas will continue to reduce our recurring overhead costs per barrel.

Reported net income was higher primarily due to the reversal of a $42.4 million deferred tax asset valuation allowance related to operating loss carryforwards (NOL's). The expected closing of the sale of our interest in Arctic Gas Company should enable the Company to realize the value of the NOL's.

The Company also recorded an increase of $11.0 million to stockholders' equity to reflect the utilization of NOL's on stock option exercises. As a result of the Company's earnings and this adjustment, stockholders' equity increased $54.7 million to $67.6 million.

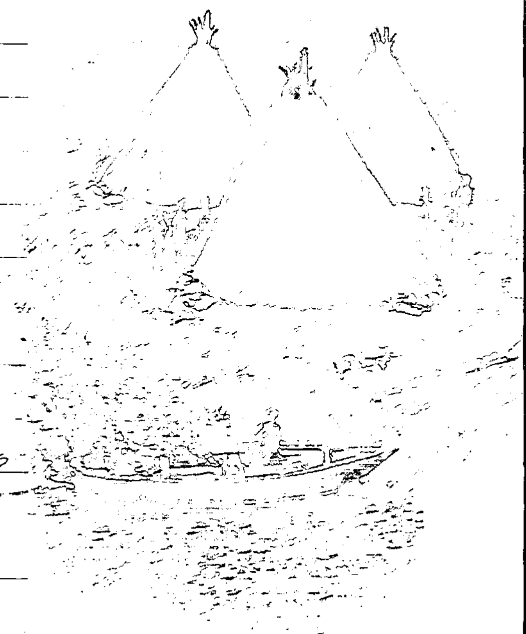


The Sikorsky helicopter is the most efficient and fastest form of transport in the tundra, but roads and sledges carry the heavy equipment.

HARVEST AHEAD...

The cumulative successes of 2001, including the Arctic Gas transaction validates our business strategy, which supports steady investment, prudent risk management and timely harvest of large resources of hydrocarbons for attractive value. We also believe the sale is indicative of the underlying value of the remaining properties in the Benton portfolio, which, to date, has been largely unrecognized by the financial markets due to our heavy debt load of the past.

The forward momentum we bring into the new year gives us renewed confidence in the Company's future. As a result, the management team will mark the beginning of its new quest for value by recommending to shareholders a name change to Harvest Natural Resources, Inc. at the upcoming

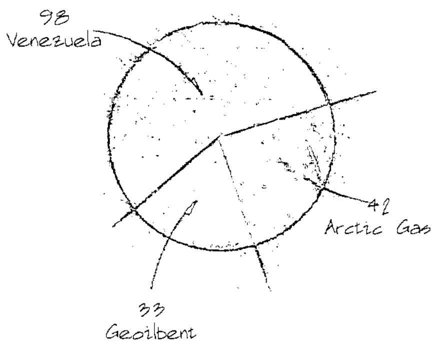


The Nenets survive in the tundra by following their reindeer herds and fishing. Using outboards helps in the summer.

shareholders meeting in May. If approved, we will soon trade on the New York Stock Exchange under the ticker symbol HNR.

OPERATING POSITION STABILIZED...

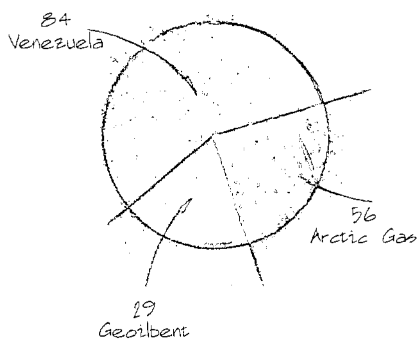
2000 Proved Reserves



2000 - 173 million barrels

As of December 31, 2001, the Company had total estimated proved reserves of 169 MMBOE, slightly down from the 173 MMBOE of 2000. The proved reserves to annual production rate (R/P) ratio remains at 17 years. Excluding the Arctic Gas proved reserves which are being sold, the Company begins the year with proved reserves of 113 million barrels and an R/P ratio of 12 years. As the Russian and Venezuelan market for natural gas emerges, we would expect to be able to record additional proved natural gas reserves as natural gas is delivered to these markets.

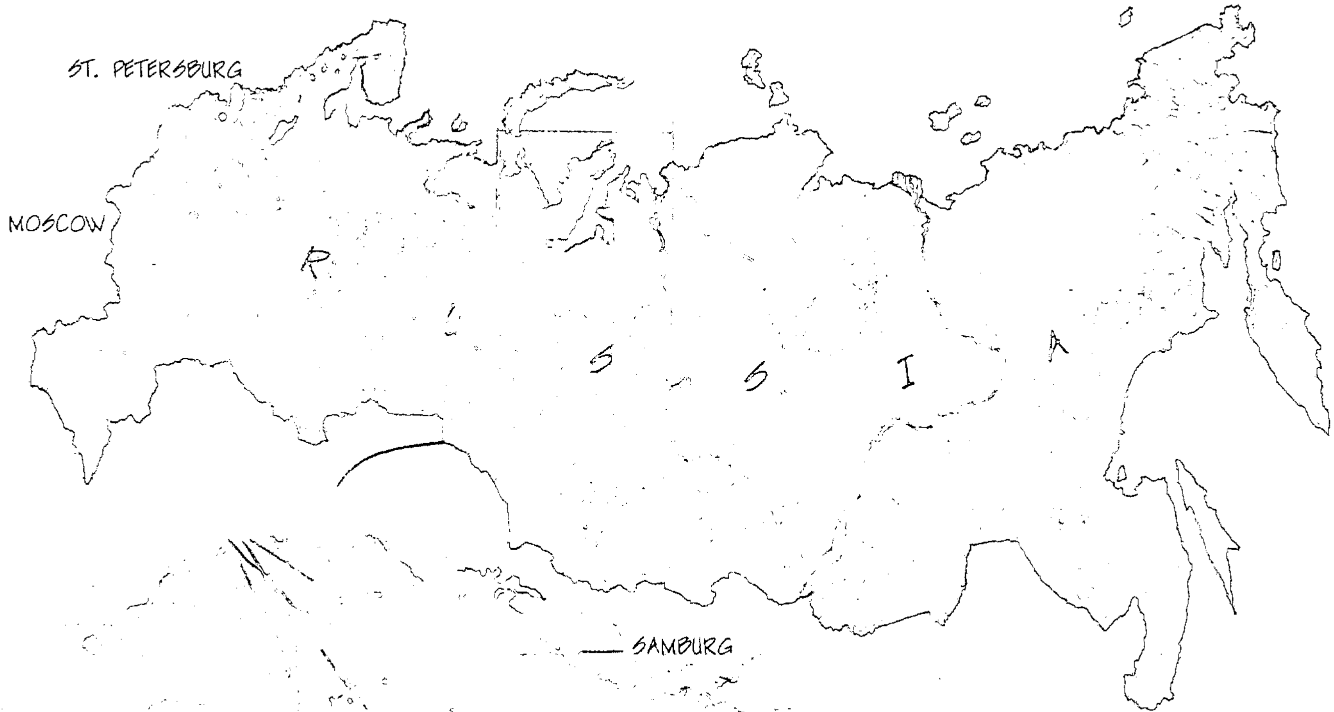
2001 Proved Reserves



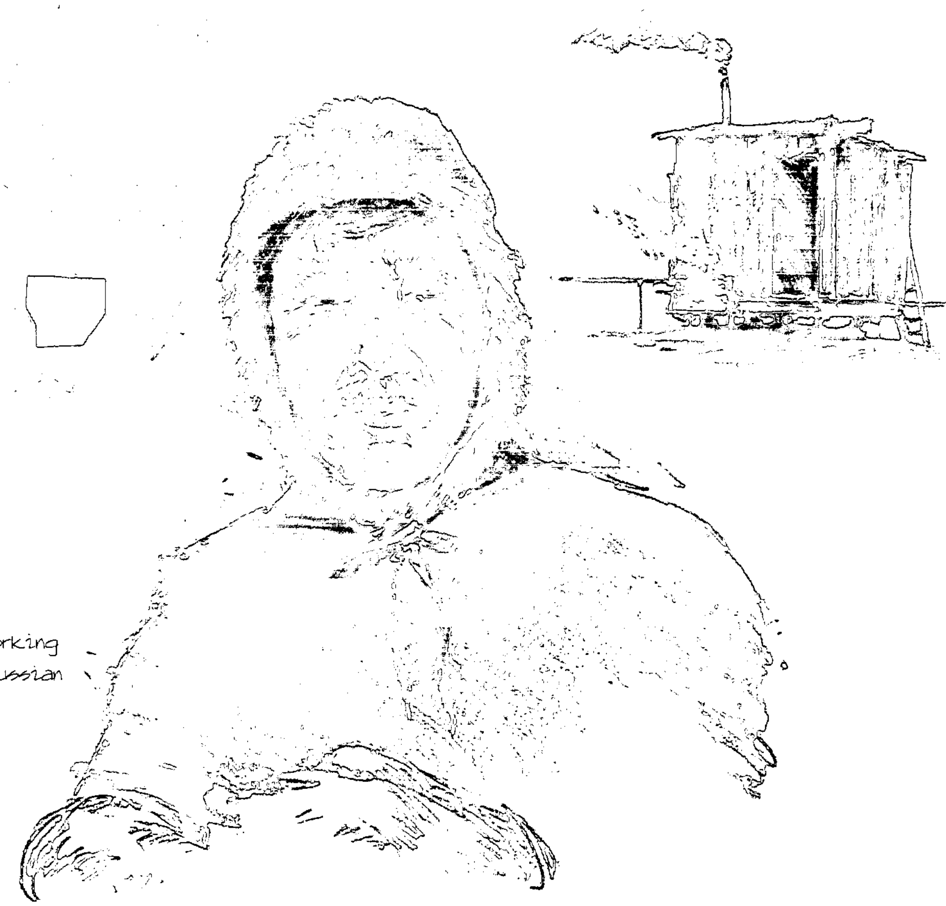
2001 - 169 million barrels
(113 million barrels without Arctic Gas)

At the same time, we increased production in 2001 by 4 percent to 9.8 million barrels, despite suspending our Venezuelan drilling program for eight months while we were working on our field simulation study. As a result of the study and our new plan for development, two high impact Tucupita Field wells in Venezuela have been drilled and completed. Each is currently producing 2,000 barrels of oil per day as of late March 2002, although we do anticipate the usual decline in production followed by lower but more sustainable production rates. We intend to drill another five of these wells in Tucupita during 2002.

Russia



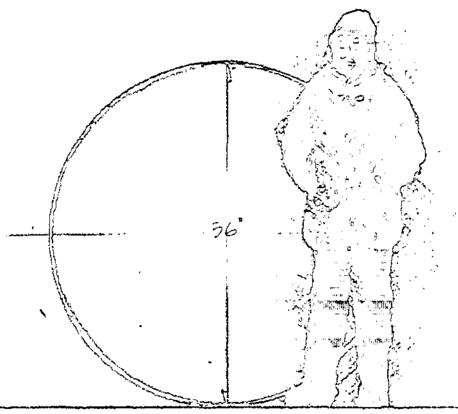
Detailed location map of our license areas in West Siberia, inside the Arctic Circle.



Harsh, remote working conditions for Russian drillers.

FROM THE RUSSIAN FRONTIER...

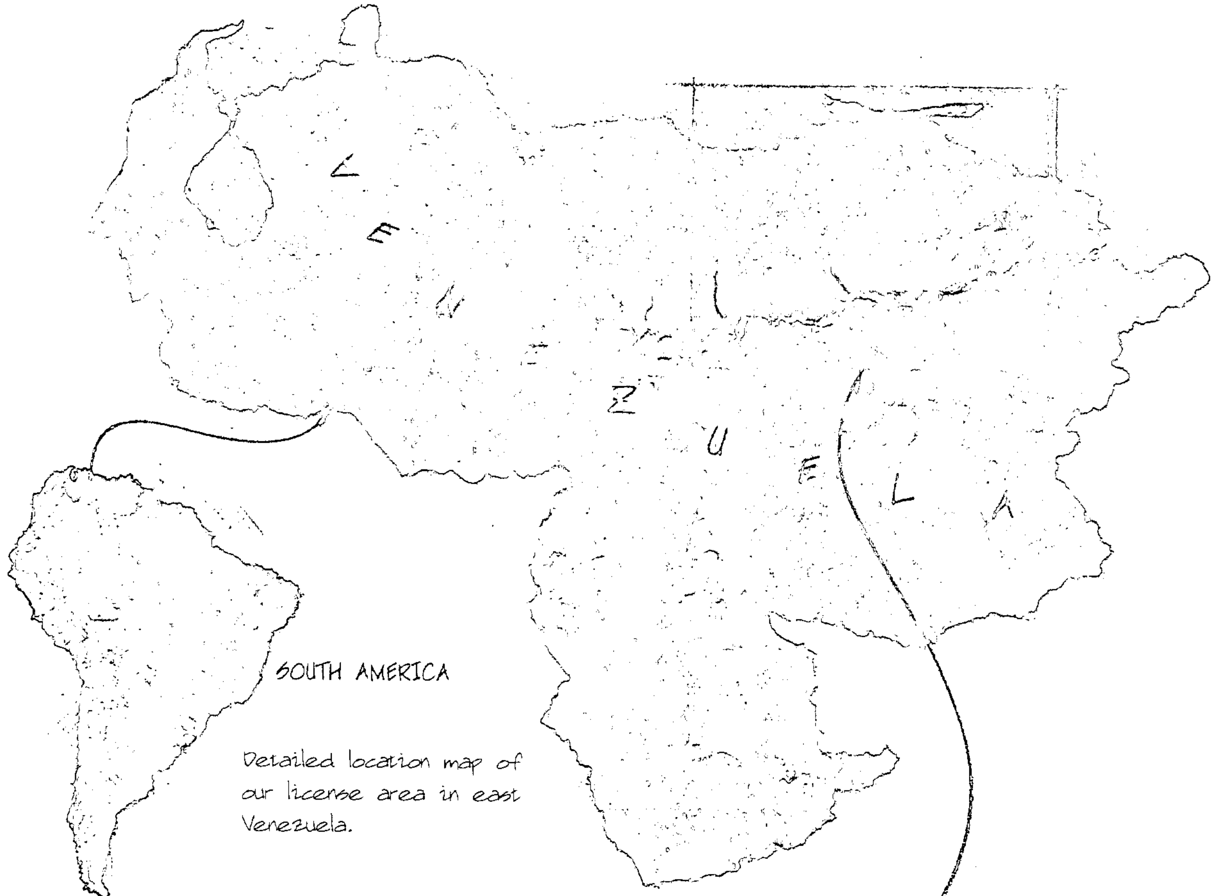
In Russia, there are near-term investment opportunities in the Gubkinsky natural gas plant and South Tarasovskoye oil field. This is accessible though our 34 percent investment in Geoilbent, a joint venture between the Company and a Russian independent. While we are only a minority owner, we are in the process of driving a restructuring of the management and financing of Geoilbent. The ownership structure and governance has been simplified. It will take some time to improve operations, the venture's financial structure and the cash flow and value of our investment in Geoilbent. If we are successful, this work will allow us to increase the reserve base and the oil and gas production streams significantly over the next three years, delivering a sustainable dividend stream.



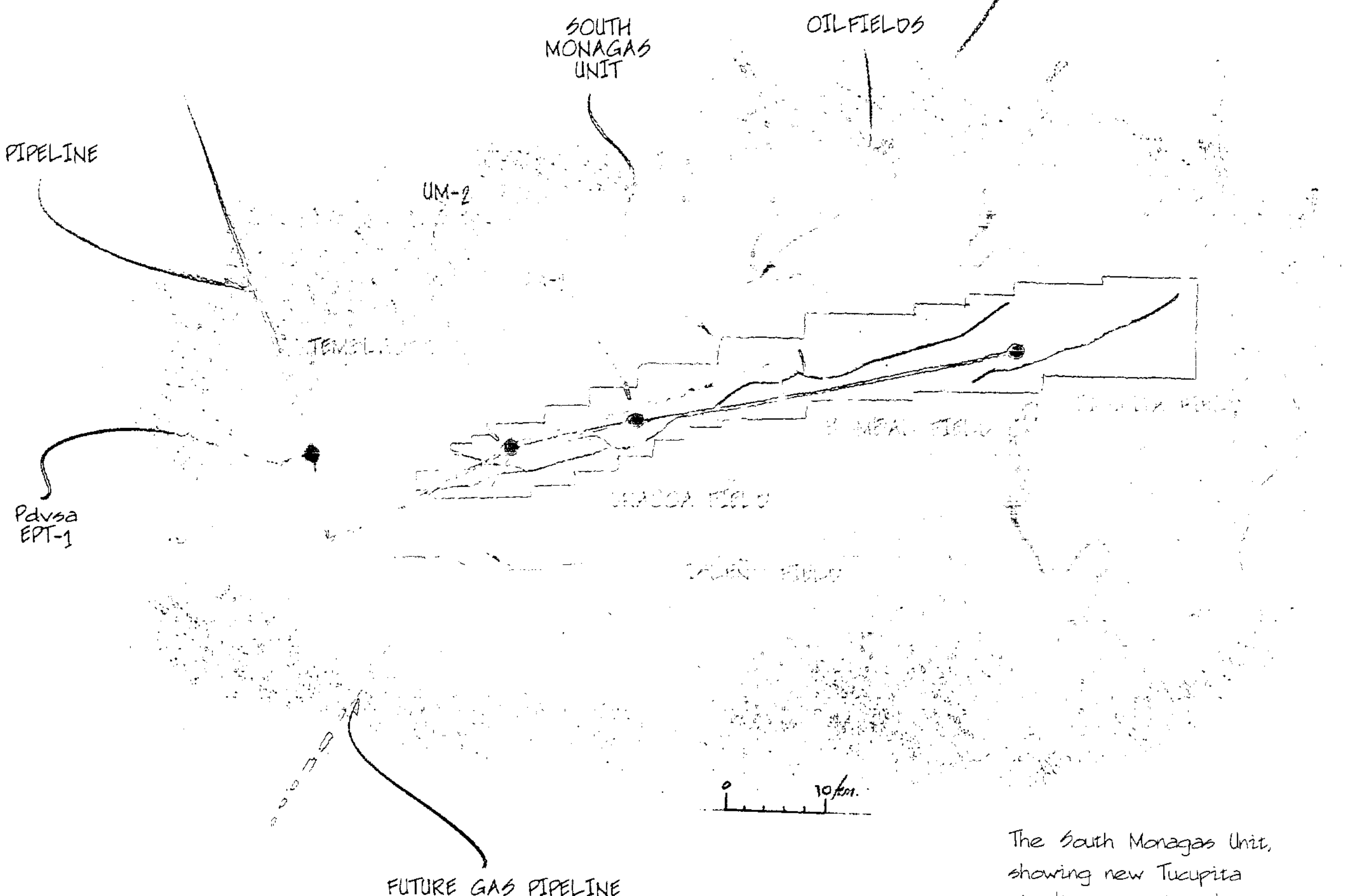
Eight 56" diameter pipelines carry the natural gas to markets in Russia, former satellite countries and to Europe.

TO ESTABLISHED VENEZUELA PRODUCTION...

In Venezuela, we are accelerating oil production from both the Uracoa and Tucupita fields, while continuing to lower costs. The newly designed, near horizontal wells drilled in Uracoa last year delivered initial production rates averaging 1,000 barrels of oil per day which was nearly double the 535 bopd we averaged in 2000. We also completed a 31-mile oil pipeline from Tucupita to our Uracoa central processing facility, which not only eliminated costly trucking charges but enabled us to accelerate development of our Tucupita reserves. This year, we expect to increase our oil production 15 to 20 percent to approximately 31,000 to 33,000 barrels per day.



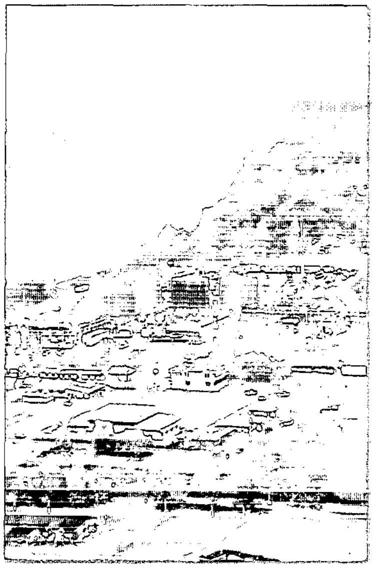
Detailed location map of our license area in east Venezuela.



The South Monagas Unit, showing new Tucupita pipeline and the planned natural gas pipeline.

Last year, we reduced our recurring cash expenses per barrel 18 percent to approximately $5.98. Increasing Venezuelan production will be a primary driver in reducing these costs another $1.00 to $2.00 per barrel this year.

We hope to negotiate a new contract with PDVSA to sell natural gas for the first time from both the Uracoa and Bombal fields, adding some 50 to 70 million cubic feet of natural gas per day to the production stream over the next three years.



The production plant and storage tanks at Tucupita on the Orinoco River. The drilling rig completes development wells, and the new pipeline passes under the river on its journey to the Uracoa facility.

NEW FUTURE IN HARVEST NATURAL RESOURCES, INC...

What's in a name? Our new company will remain focused on Venezuela and Russia. As Harvest Natural Resources, Inc., we will become known as:

- An Enabler - capable of growing relationships and securing properties with large, known hydrocarbon resources
- A Risk Manager - with the acumen to apply advanced, proven technology along with the skills to mitigate commercial and political risks
- A Prudent Investor - retaining a solid and flexible balance sheet, and rigorously testing investments against our cost of capital
- A Value Harvester - where we can grow value, taking profit when appropriate

WE WILL BE GOOD STEWARDS OF YOUR TRUST...

Your Board of Directors demands strict adherence to the highest principles of governance. We will remain transparent in all of our dealings with the financial market, governing bodies and regulatory agencies, and our employees.

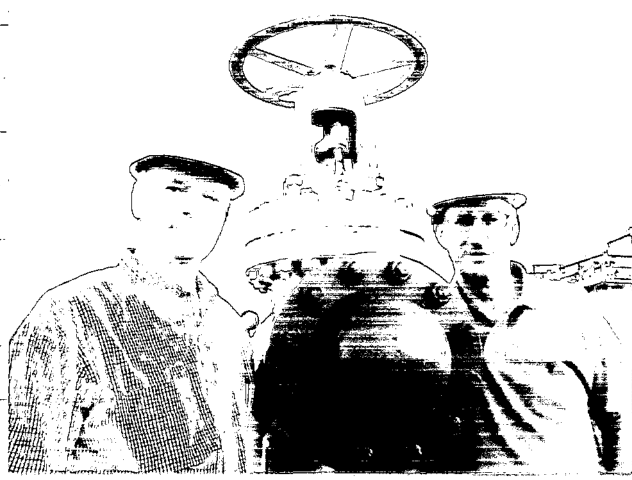
On a final note, we would like to thank the management and employee team for their tireless efforts and personal sacrifices which have contributed mightily to the Company's success. We would also like to express our appreciation to the Board for their help, work and advice.

Together, our journey will continue. We are well prepared. With your support, we will continue to benefit from each new discovery and overcome each new challenge.

Respectfully,

Stephen D. Chesebro'
Chairman

Peter J. Hill
President and
Chief Executive Officer



Stephen Chesebro' (left) and Peter Hill at the Uracoa plant.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☑ ANNUAL REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2001

or

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

For the transition period from to

Commission File No.: 1-10762

Benton Oil and Gas Company

(Exact name of registrant as specified in its charter)

Delaware *(State or other jurisdiction of incorporation or organization)*	77-0196707 *(IRS Employer Identification Number)*
15835 Park Ten Place Drive, Suite 115 Houston, Texas *(Address of principal executive offices)*	77084 *(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 ☑ No ☐

On March 25, 2002, the aggregate market value of the shares of voting stock of Registrant held by non-affiliates was approximately $138,096,369 based on a closing sales price on NYSE of $4.03.

As of March 25, 2002, 34,267,089 shares of the Registrant's common stock were outstanding.

DOCUMENT INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement for the 2002 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.

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. ☐

BENTON OIL AND GAS COMPANY

FORM 10-K

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PART I

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, budgeted, anticipate, expect, believes, goals or projects and similar expressions are intended to identify forward-looking statements. In accordance with the provisions of the Private Securities Litigation Reform Act of 1995, the Company cautions that important factors could cause actual results to differ materially from those in the forward-looking statements. Such factors include the Company's substantial concentration of operations in Venezuela and Russia, the political and economic risks associated with international operations, the anticipated future development costs for the Company's undeveloped proved reserves, the risk that actual results may vary considerably from reserve estimates, the dependence upon the abilities and continued participation of certain key employees of the Company, the risks normally incident to the operation and development of oil and gas properties and the drilling of oil and natural gas wells, the price for oil and natural gas, and other risks described in our filings with the Securities and Exchange Commission. The following factors, among others, in some cases have affected and could cause actual results and plans for future periods to differ materially from those expressed or implied in any such forward-looking statements: fluctuations in oil and natural gas prices, changes in operating costs, overall economic conditions, political stability, acts of terrorism, currency and exchange risks, changes in existing or potential tariffs, duties or quotas, availability of additional exploration and development opportunities, 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

Benton Oil and Gas Company is an independent energy corporation which has been 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"), and have acquired certain less significant interests in other parts of the world. Our producing operations are conducted principally through our 80 percent-owned Venezuelan subsidiary, Benton-Vinccler, C.A., which operates the South Monagas Unit in Venezuela; and Geoilbent Ltd., a Russian limited liability company of which we own 34 percent, which operates the North Gubkinskoye and South Tarasovskoye Fields in West Siberia, Russia. Additionally, we own 68 percent of the equity interest in Arctic Gas Company, of which 29 percent was subject to restrictions on transfer and 39 percent was not subject to restrictions on transfer, as of December 31, 2001. Arctic Gas was formed to explore and develop the Samburg and Yevo-Yakha License Blocks in the West Siberian Basin of Russia. On February 27, 2002, we entered into a Sale and Purchase Agreement ("Transaction") to sell our entire 68 percent interest in Arctic Gas Company ("Proposed Arctic Gas Sale") 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. We have expanded into other, less significant projects in China, California, and Louisiana.

As of December 31, 2001, we had total estimated proved reserves net of minority interest of 168.8 MMBOE, and a standardized measure of discounted future net cash flow, before income taxes, for total proved reserves of $365.7 million. Of these totals, the South Monagas Unit represented 83.6 MMBbls and $176.2 million, Geoilbent represented 29.6 MMBbls and $81.1 million, and Arctic Gas (based on our 39 percent unrestricted ownership) represented 55.6 MMBOE and $108.4 million.

As of December 31, 2001, we had total assets of $348.2 million. For the year ended December 31, 2001, we had total revenues of $122.4 million, cash flows from operations, before working capital changes, of $28.2 million, earnings before interest, income taxes and depletion, depreciation and amortization ("EBITDA") of $58.0 million and long-term debt of $221.6 million. For the year ended December 31, 2000, we had total revenues of $140.3 million, cash flows from operations, before working capital changes, of $47.3 million, EBITDA of $80.6 million and long-term debt of $213.0 million.

We currently have significant debt principal obligations payable in 2003 ($108 million) and 2007 ($105 million). Our ability to meet our debt obligations and to reduce our level of debt depends on the implementation of our strategic objectives, and in particular the Proposed Arctic Gas Sale. On March 22, 2002, we were notified that the Transaction had received the requisite consents from the Russian Ministry for Antimonopoly Policy and Support for Entrepreneurship. On March 28, 2002, we received the first payment ($120.0 million) of the Proposed Arctic Gas Sale proceeds. We expect that all aspects of the Transaction will be completed by April 2002. While we have no assurance that the Transaction will close, the net proceeds should be sufficient to retire early all of our 2003 debt service obligation. *See The Proposed Arctic Gas Sale if Closed Can Partially Reduce the Impact of Leverage in Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 16 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K.* In the event the Proposed Arctic Gas Sale does not close, we will evaluate alternatives with respect to our 2003 repayment obligation. In the meantime, we believe that cash flow from operations, supplemented by other asset sales or borrowings will be adequate to satisfy interest payments on outstanding debt. However, general economic conditions and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control.

Management, Operational and Financial Restrictions

We have taken the necessary steps to strengthen management, improve our operations and enhance our financial flexibility. In 2001, we completed the following:

- installed new senior management;
- redefined our strategic priorities to focus on value creation;
- initiated capital conservation steps and financial transactions, including the Proposed Arctic Gas Sale, designed to de-leverage the Company and improve our cash flow allowing debt retirement and reinvestment;
- undertook a comprehensive study of our core Venezuelan asset which focused on enhancing the value of its production;
- built the Tucupita pipeline in Venezuela to reduce transportation costs;
- sought and received relief from certain restrictive provisions of our debt instruments;
- reduced our operating expenses, corporate overhead, moved our headquarters to Houston and transferred engineering, geological and geophysical activities to our overseas offices; and
- proposed a change in our name to Harvest Natural Resources, Inc.

We continue to explore means by which to maximize stockholder value. On February 27, 2002, we entered into a Sale and Purchase Agreement ("Transaction") to sell our entire 68 percent interest in Arctic Gas Company ("Proposed Arctic Gas Sale") 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. On March 22, 2002, we were notified that the Transaction had received the requisite consents from the Russian Ministry of Antimonopoly and Support for Entrepreneurship. On March 28, 2002, we received the first payment ($120.0 million) of the Proposed Arctic Gas Sale proceeds. While no assurances can be given, we expect that all aspects of the Transaction will be completed by April 2002.

The net proceeds expected to be realized from the sale, after expenses, taxes, and the settling of certain related claims, is estimated to be approximately $150 million. These funds will be used, in part, to retire early all of the $108 million of 11⅝% senior notes, which are due in May 2003, in accordance with their terms and without penalty. We intend to use any remaining net proceeds and cash received from the repayment of loans to further reduce debt from time to time, accelerate our strategic growth in Venezuela and Russia, and for general corporate purposes. Retirement of all the outstanding 11⅝% notes eliminates $12.6 million, or $0.37 per diluted share, of annual interest expense and should mitigate near-term concern about the Company's liquidity. These retirements, plus the gain on sale, will allow us to fulfill our previous commitment to restore our balance sheet strength by reducing our debt-to-capitalization ratio from over 77% to the 41% range (see Management's Discussion and Analysis of Financial Condition and Results of Operations of Management, Operational and Financial Restrictions).

We possess significant producing properties in Venezuela, which we believe have yet to be optimized, and valuable unexploited acreage in both Venezuela and Russia. We believe the eleven new wells drilled in the South Tarasovskoye Field since July 2001 significantly increase the value of our Geoilbent properties. In December 2001 and January 2002, we spudded the first two wells in our seven well Tucupita Field program in Venezuela. We are evaluating the construction of additional processing and handling facilities and are in discussions with an affiliate of Petroleos de Venezuela, S.A. ("PDVSA") regarding a sales contract that may allow for the first-time sale of natural gas in Venezuela by our affiliate.

In May 2001, we initiated a process intended to effectively extend the maturity of the senior notes due May 1, 2003 by exchanging new 13.125 percent senior notes due December 2007 plus warrants to purchase shares of our common stock for each of the 2003 Notes. The exchange offer was withdrawn in July 2001. However, in August 2001, we solicited and received the requisite consents from the holders of both the 2003 Notes and the 2007 Notes to amend certain covenants in the indentures governing the notes to enable Arctic Gas Company to incur nonrecourse debt of up to $77 million to fund its oil and gas development program. As an incentive to consent, we paid each noteholder an amount in cash equal to $2.50 per $1,000 principal amount of notes held for which executed consents were received. The total amount of consent fees paid to the consenting noteholders was $0.3 million, which has been included in 2001 general and administrative expenses.

In June 2001, we implemented a plan designed to reduce overall general and administrative costs, including exploration overhead, at our corporate headquarters and to transfer management oversight of geological and geophysical activities to our overseas offices in Maturin, Venezuela and in Western Siberia and Moscow, Russia. The reduction in general and administrative costs was accomplished by reducing our headquarters staff and relocating our headquarters to Houston, Texas from Carpinteria, California. For 2001, we recorded non-recurring items of $11.4 million; $5.7 million of which are included in general and administrative expenses, $1.7 million of which are included in depletion, depreciation and amortization, $3.2 million in operating expenses and $0.8 in taxes other than income. The general and administrative expenses include $2.2 million on the withdrawn debt exchange, $2.2 million for severance and termination benefits for 33 employees, $1.1 million for lease relinquishment expenses and $0.2 million for relocation costs to Houston. Depletion, depreciation and amortization included $0.9 million for the reduction in the carrying value of fixed assets that were not transferred to Houston and $0.8 million loss on subleasing the former Carpinteria headquarters. All expenses were paid or accrued by December 31, 2001. The accrued balance of $0.1 million will be paid in 2002.

Operating Strategy

Our business strategy supports the steady investment, prudent risk management and timely harvest of large hydrocarbon resources for attractive values. 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.

During 2001, our operating strategy was necessarily focused on improving the efficiency and efficacies of our current operations in both Venezuela and Russia. Over the years, we have benefited from the significant capital commitment made to these areas, but have suffered financially from sub-optimal operating, contracting and risk management practices, which, for the most part, have been or are currently in the process of being significantly improved. In Venezuela, we implemented new development and production plans at Benton-Vinccler following an eight-month suspension of drilling and an extensive reservoir study, which resulted in increased production, lower operating costs and added confidence in our future drilling plans to extend the life and value of the field. We have also streamlined decision making, improved internal controls and implemented industry standard techniques to mitigate geologic, operating, financial and political risks attendant with doing business in Venezuela.

In Russia, where we are a minority owner in Geoilbent, we are attempting to pursue a similar course with the help of other interest owners, in order to improve operations and extend the life of the field, lower operating costs and enhance financial results. These assets represent significant potential value for us, but remain subject to sub-optimal operating conditions while our lack of majority control over its operations could inhibit our ability to implement necessary changes in management, operations or financing matters.

In both Venezuela and Russia, and in other countries around the world, the development of local markets for natural gas represents a significant opportunity for us. However, the development of these markets, in large part, depends upon substantial capital investment by third parties in the infrastructure needed to produce, gather, treat, transport, store and convert natural gas into marketable products. While this investment is beginning to materialize in many of these markets, it will take many years, in some instances, to place such assets into service. We are well positioned to benefit from the emergence of new regional gas markets in proximity to our reserves.

Our long-term strategy is to identify, access and exploit large resources of hydrocarbons in underexploited areas around the world that can be developed at low overall finding costs, produced at low operating costs and converted into proved reserves, production and value. While our success is dependent upon many factors both within and outside of our control, in order to achieve this strategy, we must:

- continue to improve our financial flexibility and financing strategies;
- exploit our core assets in Venezuela and Russia; and
- seek and exploit new oil and natural gas resources in our core areas.

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 exploration and development activities only in areas of known, proven hydrocarbons.
- *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.

Operations

The following table summarizes our proved reserves, drilling and production activity, and financial operating data by principal geographic area at and for each of the three years ended December 31. All Venezuelan reserves are attributable to an operating service agreement between Benton-Vinccler and an affiliate of PDVSA under which all mineral rights are owned by the Government of Venezuela. Geoilbent and Arctic Gas Company are accounted for under the equity method and have been included at their respective ownership interest 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, 2001, 2000 and 1999 reflect results from Geoilbent for the twelve months ended September 30, 2001, 2000 and 1999, and from Arctic Gas 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 July 2012.

	Benton-Vinccler		
	Year Ended December 31,		
	2001	2000	1999
	(Dollars in 000's)		
RESERVE INFORMATION:			
Proved reserves (MBbls)	83,611	98,431	107,969
Discounted future net cash flow attributable to proved reserves, before income taxes	$176,210	$368,464	$521,346
Standardized measure of future net cash flows	$163,328	$284,549	$380,865
DRILLING AND PRODUCTION ACTIVITY:			
Gross wells drilled	8	26	2
Average daily production (Bbls)	26,788	25,585	26,485
FINANCIAL DATA:			
Oil and natural gas revenues	$122,386	$139,890	$ 89,060
Expenses:			
Operating expenses and taxes other than on income	42,212	46,848	38,839
Depletion	22,119	15,708	14,732
Income tax expense	8,932	19,768	3,822
Total expenses	73,263	82,324	57,393
Results of operations from oil and natural gas producing activities	$ 49,123	$ 57,566	$ 31,667

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, drilling and production activity, and financial operating data for the twelve months ended September 30, 2001, 2000, and 1999.

	Geoilbent		
	Year Ended September 30,		
	2001	2000	1999
	(Dollars in 000's)		
RESERVE INFORMATION:			
Proved reserves (MBbls)	29,669	32,615	36,415
Discounted future net cash flow attributable to proved reserves, before income taxes	$81,125	$140,160	$215,348
Standardized measure of future net cash flows	$70,648	$114,725	$169,077
DRILLING AND PRODUCTION ACTIVITY:			
Gross development wells drilled	39	39	28
Net development wells drilled	13	13	10
Average daily production (Bbls)	4,830	3,945	3,975

	Geoilbent		
	Year Ended September 30,		
	2001	2000	1999
	(Dollars in 000's)		
FINANCIAL DATA:			
Oil and natural gas revenues	$34,394	$ 26,770	$ 12,511
Expenses:			
Selling and distribution expenses	3,358	1,568	1,369
Operating expenses and taxes other than on income	12,671	9,548	4,274
Depletion	5,072	3,249	3,287
Income tax expense	3,204	3,215	442
Total expenses	24,305	17,580	9,372
Results of operations from oil and natural gas producing activities	$10,089	$ 9,190	$ 3,139

As of December 31, 2001, 2000 and 1999, we owned, free of any sale and/or transfer restrictions, 39, 29 and 24 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, drilling and production activity, and financial operating data for the twelve months ended September 30, 2001 and 2000.

	Arctic Gas Company		
	Year Ended September 30,		
	2001	2000	1999
	(Dollars in 000's)		
RESERVE INFORMATION:			
Proved reserves (MBOE)	55,631	41,236	3,714
Discounted future net cash flow attributable to proved reserves, before income taxes	$108,400	$74,517	$8,241
Standardized measure of future net cash flows	$ 82,205	$56,880	$6,836
DRILLING AND PRODUCTION ACTIVITY:			
Gross wells reactivated	2	4	—
Average daily production (BOE)	502	134	—
FINANCIAL DATA:			
Oil and natural gas revenues	$ 4,016	$ 889	$ —
Expenses:			
Selling and distribution expenses	1,165	—	—
Operating expenses and taxes other than on income	2,215	604	—
Depletion	311	78	—
Total expenses	3,691	682	—
Results of operations from oil and natural gas producing activities	$ 325	$ 207	$ —

South Monagas Unit, Venezuela (Benton-Vinccler)

General

In July 1992, Benton and Venezolana de Inversiones y Construcciones Clerico, C.A., a Venezuelan construction and engineering company ("Vinccler"), signed a 20-year operating service agreement with Petroleo y Gas, 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 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. Benton-Vinccler invoices PDVSA each quarter based on barrels of oil accepted by PDVSA during the quarter, using quarterly adjusted contract service fees per barrel. Benton-Vinccler receives its payments from PDVSA in U.S. dollars deposited directly into a U.S. bank account. 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.

In December 1999, Benton-Vinccler entered into an alliance with Schlumberger for the Uracoa field which includes reservoir modeling, drilling and downhole electrical pumping. The alliance gives us access to Schlumberger's technical resources and personnel and provides financial incentives for Schlumberger based on their performance. The incentives are designed to reduce drilling costs, improve initial production rates of new wells and increase the average life of downhole pumps. Schlumberger maintains a full-time staff at Benton-Vinccler's office as part of this agreement. We signed an amendment to the alliance in 2001 whereby Schlumberger agreed to provide drilling and completion services for new wells utilizing fixed lump-sum pricing. The amended alliance continues to provide incentives to Schlumberger designed to improve initial production rates of new wells and to increase the average life of the downhole pumps.

We drilled eight oil wells in 2001. As part of our strategic shift in focus on the value of the barrels produced, we suspended the development drilling program for a period of approximately eight months starting in January 2001. During this period, with the assistance of alliance partner Schlumberger, all aspects of operations were thoroughly reviewed to integrate field performance to date with revised computer simulation modeling and improved well completion technology. We believe this helped to produce a streamlined and more effective infill drilling and well workover program that is part of an overall reservoir management strategy.

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. At December 31, 2001, proved reserves attributable to our Venezuelan operations were 104,514 MBbls (83,611 MBbls net to Benton). This represented approximately 50 percent of our proved reserves. Benton-Vinccler has been primarily developing the Oficina sands in the Uracoa Field. The Uracoa Field contains 70 percent of the South Monagas Unit's proved reserves. In December 2001, Benton-Vinccler began the development of the Tucupita Field. We intend to drill seven oil wells and two water injection wells in the Tucupita Field during 2002. Benton-Vinccler is currently reinjecting most of the associated natural gas produced at Uracoa back into the reservoir.

Natural Gas Sale Negotiations

We are currently in discussions with PDVSA regarding the negotiation of a contract contemplating the sale of natural gas produced from the South Monagas Unit. Benton-Vinccler anticipates natural gas from the Uracoa and Bombal Fields could be dedicated to PDVSA over the remaining life of the operating service agreement. If the parties reach an agreement, construction of a pipeline, compressor and other necessary infrastructure may be required in order to deliver natural gas to PDVSA in accordance with agreed specifications. However, there are no assurances that a natural gas contract will result from these negotiations.

Drilling and Development Activity

Benton-Vinccler drilled 8 wells and had an average of 133 wells on production in all fields in 2001.

Uracoa Field

Benton-Vinccler has been developing the South Monagas Unit since 1992, beginning with the Uracoa Field. The following table sets forth the Uracoa Field drilling activity and production information for each of the quarters presented:

	Wells Drilled		Average Daily
	Vertical	Horizontal	Production from Field (Bbls)
1999:			
First Quarter	—	—	24,300
Second Quarter	—	—	22,800
Third Quarter	—	—	21,300
Fourth Quarter	—	—	21,000
2000:			
First Quarter	6	—	19,800
Second Quarter	9	1	20,500
Third Quarter	2	3	21,900
Fourth Quarter	2	3	23,100
2001:			
First Quarter	—	—	26,100
Second Quarter	—	—	20,500
Third Quarter	2	—	19,700
Fourth Quarter	5	1	20,700

In 1998, we developed a geologic and reservoir simulation study which indicated the viability of multiple additional primary infill wells in the Uracoa Field. We believe many of these new locations are in underdeveloped sands where the model may help to optimize well spacing and location. In the more developed areas of the field, we used the model to verify our economic assumptions regarding infill locations. In the first quarter of 2001, we began a comprehensive technical review of the South Monagas Unit that includes the completion of an extensive geologic and reservoir computer simulation study which we believe will assist in optimizing field management. The computer simulation study, built jointly with Schlumberger, may update and extend the 1998 study performed on a portion of the Uracoa Field to the entire South Monagas Unit. It will incorporate all new geologic and reservoir information as well as the total production and drilling history from the more mature Uracoa Field and the underdeveloped Tucupita and Bombal Fields. We expect several benefits from the study including an optimum production profile of oil and gas, a revised water and natural gas injection strategy, more efficient development locations and improved well completion techniques. We anticipate completing a revised Uracoa Field development plan, incorporating the results of this study, in mid-2002.

Since 1992, we have reactivated 15 previously drilled wells and drilled 147 new wells in the Uracoa Field using improved drilling and completion techniques that had not previously been utilized on the field. Of the new wells drilled, 6 wells were drilled as water or natural gas injector wells and an additional 6 producing wells have been converted into injection wells. Two of the drilled injector wells were subsequently converted into producing wells.

We process the oil, water and natural gas produced from the Uracoa Field in the Uracoa central processing unit. We ship the processed oil via pipeline to the PDVSA custody transfer point. We treat and filter produced water, and then re-inject it into the aquifer to assist the natural water drive. We re-inject 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 50 Mcf 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

Before becoming inactive in 1987, the Tucupita Field had been substantially developed. It had produced 67.1 MMBbls of oil, 34.7 MMBbls of water and 17.6 Bcf of natural gas. Benton-Vinccler drilled a successful pilot horizontal well in late 1996 to evaluate the remaining development potential of the Tucupita Field. This well has produced 1.9 MMBbls of oil at an average rate of 987 Bbls of oil per day. The early success of this pilot horizontal well led to the drilling of a second horizontal well in 1998. Initial oil rates from the horizontal wells were encouraging, but water production soon increased sharply. As a result, we changed the redevelopment strategy to include drilling deviated wells to allow for more effective water shut-off. During the second half of 1998, we drilled five deviated infill wells to target undepleted portions of the field and reactivated an additional nine wells. All five drilled wells encountered high oil saturations, with an average initial production rate of 922 Bbls of oil per day. In 2001, we reactivated nine wells in Tucupita and identified seven new well locations in what we believe are undepleted portions of the Tucupita Field, which we anticipate drilling in 2002. As a result of our analysis of the potential in the Tucupita Field, and for environmental and safety reasons, we constructed a $10.3 million, 31-mile, 20,000 Bbl per day capacity oil pipeline from Tucupita to the Uracoa central processing unit in 2001.

We are 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 date, we have drilled one well in the Bombal Field and reactivated another. The Bombal Field is now shut-in. We are currently evaluating the future development plan for Bombal in light of our negotiations with PDVSA concerning the sale of natural gas.

Customers and Market Information

Oil produced in Venezuela is delivered to PDVSA under the terms of an operating service agreement for an operating service fee. Benton-Vinccler has constructed a 25-mile oil pipeline from its oil processing facilities at Uracoa to PDVSA's storage facility. This is the custody transfer point. The 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. We installed a continuous flow measuring unit at our facility to closely monitor the quantities of hydrocarbons delivered to PDVSA. This flow measuring unit was completed in January 2002. PDVSA provides Benton-Vinccler with a daily acknowledgment regarding the amount of oil accepted during the previous day. At the end of each quarter, Benton-Vinccler prepares an invoice to PDVSA for that quarter's deliveries. PDVSA pays 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.

Natural gas produced by Benton-Vinccler is currently re-injected or used as fuel gas in operations. We are currently in negotiations with PDVSA for sale of natural gas in the South Monagas Unit. There are no assurances that natural gas contracts will result from these negotiations.

Employees and Community Relations

Benton-Vinccler has a highly skilled staff of predominately Venezuelan nationals. Benton-Vinccler has also formed successful and supportive relationships with local government agencies and communities. There are 174 local employees and 5 expatriates working at Benton-Vinccler.

Benton-Vinccler has invested in a Social Community Program that includes medical care programs such as in ophthalmologic and dental care. From 1994 to 2001, a total of 340 eye surgeries were performed on patients ranging in age from two to eighty-five years, solely as a result of financial assistance provided by Benton-Vinccler. The dental program focuses on comprehensive dental care for public school children. From 1994 to 2001, the program has involved approximately 1,825 children. Additional social investments include sponsoring the purchase of medicines and medical equipment in local communities within the South Monagas Unit, as well as supporting local schools, education programs and environmental improvements.

Health, Safety and Environment

Benton-Vinccler's health, safety and environmental policy is an integral part of its business. Annually, improvements have been made in operating performance, 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. Geoilbent's ownership is as follows:

- Benton owns 34 percent;
- Open Joint Stock Company Minley ("Minley") owns 66 percent.

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. We believe that we have developed a good relationship with our shareholder and have not experienced any disagreements on major operational matters. Purneftegazgeologia and Purneftegas (co-founding shareholders) contributed their interest to Minley in 2001. We are reviewing ways to improve the operations, but we are a minority partner and therefore may not be able to fully effect changes in operations, if indicated by our review. Geoilbent shareholder action requires a 67 percent majority vote of its shareholders.

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 proven oil and gas fields surround all four of Geoilbent's licenses.

The North Gubinskoye 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 BP 8, 9, 10, 11 and 12 reservoirs with minor development in the BP 6 and 7 reservoirs. Geoilbent is currently flaring the produced natural gas in accordance with environmental regulations, although it is exploring alternatives to market the natural gas.

The South Tarasovskoye Field is located a few miles southeast of North Gubinskoye Field and straddles the eastern boundary of the Urabor Yakhinsky exploration block acquired by Geoilbent in 1998. It is estimated 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.

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

Drilling and Development Activity

Geoilbent commenced initial operations in the North Gubinskoye Field during the third quarter of 1992 with the construction of a 37-mile oil pipeline and installation of temporary production facilities. During 2001, approximately 110 wells were producing with 29 injection wells. Drilling in South Tarasovskoye Field began at the end of May 2001. The first well was completed on July 23, 2001 for an initial production rate of 1,695 Bbls oil per day. In 2001, Geoilbent drilled 11 wells at an average production rate of 880 Bbls oil per day. By the end of 2001, total production from the 11 wells was 9,700 Bbls oil per day. Plans are to drill between 50 to 60 more wells by 2005 to more fully develop the portion of the field within the Urabor block.

The following table sets forth drilling activity and production information for each of the quarters presented:

	Wells Drilled	Average Daily Production from Field (Bbls)
1999:		
First Quarter	5	10,500
Second Quarter	6	11,400
Third Quarter	8	13,000
Fourth Quarter	9	13,200
2000:		
First Quarter	2	11,200
Second Quarter	12	12,700
Third Quarter	15	13,900
Fourth Quarter	10	14,700
2001:		
First Quarter	7	13,900
Second Quarter	8	13,300
Third Quarter	12	14,700
Fourth Quarter	12	14,900

Geoilbent contracts with third parties for drilling and completion of wells. To date, 38 previously drilled wells have been reactivated and 153 wells have been drilled in the field. A total of 129 wells, or 84 percent, have been completed and placed on production, 20 of which were converted to water injection wells. Each well is drilled to an average measured depth of approximately 9,000 feet and an average true vertical depth of 8,000 feet. The current production facilities are operating at or near capacity and will need to be expanded to accommodate production increases.

Geoilbent transports oil produced from the North Gubkinskoye Field to production facilities constructed and owned by Geoilbent. It then transfers the oil to Geoilbent's 37-mile pipeline, which transports the oil from the North Gubkinskoye Field south to the main Russian oil pipeline network.

Geoilbent has obtained financing through a $65 million parallel loan facility for the development of the North Gubkinskoye Field from the European Bank for Reconstruction and Development ("EBRD") and the International Moscow Bank. A total of $48.5 million had been advanced from the loan facility. Debt outstanding under the facility at December 31, 2001 was $38.6 million. As of September 30, 2001, Geoilbent was not in compliance with the current ratio covenant but received a waiver from EBRD through March 31, 2002.

Geoilbent has reduced its 2002 capital budget to approximately $16.6 million, of which $2.7 million is for the North Gubkinskoye Field, $9.7 million is for the South Tarakovskoye Field, $2.2 million is to carry out seismic and related exploration activity and $2.0 million is for natural gas plant economic, technical and feasibility studies. Geoilbent's 2002 operating budget includes $16 million for principal payments on the loan facility. In addition, Geoilbent had outstanding accounts payable of $26.6 million as of December 31, 2001, primarily to contractors and vendors for drilling and construction services.

Although Geoilbent's reduced capital expenditure budget may help to alleviate any shortfall of funds available to make payments to the banks and its creditors as those payments come due, it is uncertain that Geoilbent's cash flow from operations will be sufficient to do so, and it may be necessary for Geoilbent to obtain capital contributions from its partners, including the Company, to have sufficient funds to make these payments on a timely basis. Although the Company may consider making such a capital contribution, there can be no assurances that the Company will do so, nor can there be any assurances that Geoilbent's other partner will be willing or able to do so. Under Russian law, a creditor can force a company into involuntary bankruptcy if the company's payments have been due for more than 90 days.

Customers and Market Information

Geoilbent's 37-mile pipeline runs from the field to the main pipeline in the area where Geoilbent transfers the oil 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 handle all export oil sales. All export sales have been paid in U.S. dollars into Geoilbent's account in Moscow. Domestic sales are paid in Russian Rubles. During 2001, Geoilbent sold approximately 49 percent of its production in the export market and 51 percent in the domestic market. Excise, pipeline and other tariffs and taxes continue to be levied on all oil producers and certain exporters, including an oil export tariff that decreased in 2002 to $8.00 per ton (approximately $1.10 per barrel) from 23.4 Euros per ton (approximately $2.85 per barrel). We are unable to predict the impact of taxes, duties and other burdens for the future for our Russian operations.

Employees; Community and Country Relations

Geoilbent employs Russian nationals almost exclusively. Presently, there are two full-time 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 reside in the area of oilfield operations.

East Urengoy, Russia (Arctic Gas Company)

General

See The Proposed Sale of Arctic Gas Company, if Closed, Will Reduce the Impact of Leverage in Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations, and Note 16 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K.

Arctic Gas Company, formerly Severneftegaz, was formed in 1992 as a private company to explore and develop the Samburg and Yevo-Yakha License Blocks. The Samburg and Yevo-Yakha License Blocks are located within the West Siberian Basin, the world's largest sedimentary basin, which contains a significant portion of the world's natural gas reserves. Both license blocks are on the eastern flank of the giant Urengoy natural gas field, which currently produces hydrocarbons from Cenomanian reservoirs. Under the terms of agreements signed in April 1998, we acquired a 40 percent interest in Arctic Gas in return for providing or arranging up to $100 million of credit financing for the project. Our agreements impose restrictions on the sale and transfer of these shares subject to disbursements under the credit financing and provide that for every $2.5 million of credit made available, 1 percent of the interest will be released from the restrictions.

As of December 31, 2001, we had provided $28.5 million of credit, of which $28.1 million had been applied to the release of restrictions on the shares. As a result, we removed restrictions from shares representing an approximate 11 percent equity interest. From 1998 through December 2001, we separately purchased shares representing an additional 28 percent equity interest not subject to any sale or transfer restrictions. Including the additional purchased shares, as of December 31, 2001, we owned a total of 68 percent of the voting shares of Arctic Gas, of which 39 percent was not subject to restrictions.

The following table summarizes our ownership interests of Arctic Gas Company:

	As of December 31, 2001	As of December 31, 2000
Shares released from restrictions	11%	9%
Additional purchased shares	28%	20%
Total shares not subject to restrictions	39%	29%
Shares subject to restrictions	29%	31%
Total ownership	68%	60%

In February 2002, we announced the Proposed Arctic Gas Sale. On March 22, 2002, we were notified that the Transaction had received the requisite consents from the Russian Ministry for Antimonopoly Policy and Support for Entrepreneurship. On March 28, 2002, we received the first payment ($120.0 million) of the Proposed Arctic Gas Sale proceeds.

Location and Geology

The Samburg and Yevo-Yakha License Blocks comprise 794,972 acres and are situated approximately 150 miles north of our Geoilbent affiliates' operations in the Yamal-Nenets Autonomous Region of Russia. The towns and communities of Novy Urengoy, Samburg, Urengoy and Nyda are located near the two licenses. Extensive exploration drilling and testing (over 90 wells) on the Samburg and Yevo-Yakha licenses has resulted in the discovery of major resources of natural gas, condensate and oil. The primary reservoirs of these fields are currently being produced in both the adjacent Urengoy Field and Rospan Block.

Drilling and Development Activity

Arctic Gas has reactivated 8 previously drilled oil wells through March 23, 2002. We are trucking oil to storage facilities where it is collected for sale. Arctic Gas is currently producing approximately 2,700 Bbls of oil per day.

The following table sets forth reactivation activity and production information for each of the quarters presented:

	Wells Reactivated	Average Daily Production from Field (Bbls)
2000:		
First Quarter	—	400
Second Quarter	2	940
Third Quarter	1	1,500
Fourth Quarter	1	1,700
2001:		
First Quarter	1	1,300
Second Quarter	—	1,000
Third Quarter	—	2,300
Fourth Quarter	1	2,100

Arctic Gas is currently planning for a Samburg oil and natural gas pilot development project. The pilot project calls for:

- drilling new wells;
- installing natural gas processing facilities; and
- connecting into the export pipeline system.

The Arctic Gas blocks are located in the heart of the Urengoy/Yamburg producing and support infrastructure region and are well situated for development. Natural gas export trunklines are located 11 kilometers from the blocks. Arctic Gas and Gazprom have entered into agreements to allow access to existing oil, liquids and natural gas pipelines and facilities that could potentially result in product sales to domestic and export markets. *See Note 16 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K.* Arctic Gas had entered into contracts with various parties concerning the export of natural gas. All natural gas contracts have been cancelled pursuant to the Proposed Arctic Gas Sale.

Further development activities are subject to the pace and scope of Arctic Gas's internally generated funds and to our ability to provide or arrange further funding.

Employees; Community and Country Relations

Arctic Gas is a Russian company that employs Russian nationals almost exclusively. Presently, there are 2 full-time expatriates working with Arctic Gas and 161 local employees. We have conducted community relations programs in Russia, providing medical care, training, equipment and supplies in towns in which Arctic Gas personnel reside and also for the nomadic indigenous population which reside in the area of oilfield operations.

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

General

In December 1996, we acquired Crestone Energy Corporation, a privately held company headquartered in Denver, Colorado, 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 1.0 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 Conoco Inc. The dispute has lasted for many years, and there has been limited exploration and no development activity in the area under dispute.

We cannot predict how or when, if at all, this dispute will be resolved or whether it would result in our interest being reduced.

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, we have been unable to pursue an exploration program during phase one of the contract. As a result, we have obtained extensions, with the current extension in effect until May 31, 2003.

Domestic Operations

In April and May 2000, we entered into agreements with Coastline Energy Corporation ("Coastline") for the purpose of acquiring, exploring and developing oil and natural gas prospects both onshore and in the state waters of the Gulf Coast states of Texas, Louisiana and Mississippi. We acquired a 100 percent working interest in the Lakeside Exploration Prospect in Cameron Parish, Louisiana. We farmed out 90 percent of the working interest in the prospect for $0.5 million cash and a 16.2 percent carried interest in the first well. We anticipate that drilling of the well may commence in 2002. The agreement with Coastline was terminated on August 31, 2001. However, certain ongoing operations related to the Lakeside Exploration Prospect are conducted by Coastline on a consulting basis.

In March 1997, we acquired a 40 percent participation interest in three California State offshore oil and natural gas leases ("California Leases") from Molino Energy Company, LLC ("Molino Energy"), which held 100 percent of these leases. The project area covers the Molino, Gaviota and Caliente Fields, located approximately 35 miles west of Santa Barbara, California. In consideration of the 40 percent participation interest in the California Leases, we became the operator of the project and agreed to pay 100 percent of the first $3.7 million and 53 percent of the remainder of the costs of the first well drilled on the block. During 1998, the 2199 #7 exploratory well was drilled to the Gaviota anticline. Drill stem tests proved to be inconclusive or non-commercial, and the well was temporarily abandoned for further evaluation. In November 1998, we entered into an agreement to acquire Molino Energy's interest in the California Leases in exchange for the release of their joint interest billing obligations. In the fourth quarter of 1999, we decided to focus our capital expenditures on existing producing properties and fulfilling work commitments associated with our other properties. Because we had no firm approved plans to continue drilling on the California Leases and the 2199 #7 exploratory well did not result in commercial reserves, we wrote off 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. However, we continue to evaluate the prospect for potential future drilling activities.

Activities by Area

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

	Venezuela	Other Foreign	Total Foreign	United States	Total
			(In thousands)		
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
Year ended December 31, 1999					
Oil sales	$ 89,060		$ 89,060		$ 89,060
Total Assets	$124,942	$ 61,989	$186,931	$89,380	$276,311

Reserves

Estimates of our proved reserves as of December 31, 2001 and 2000 were prepared by Ryder Scott Company, LP, independent petroleum engineers. In prior years, reserve estimates were prepared by us and audited by Huddleston & Co., Inc., independent petroleum engineers. The following table sets forth information regarding estimates of proved reserves at December 31, 2001. 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. Although we estimate that there are substantial natural gas reserves in the Benton-Vinccler properties in Venezuela and the license blocks held by Geoilbent, no natural gas reserves have been recorded as of December 31, 2001 because of a lack of sales and/or transportation contracts in place. Geoilbent and Benton-Vinccler are currently evaluating alternatives to market this natural gas. Natural gas proved reserves have been recognized for Arctic Gas, which has transportation and marketing contracts in place. The marketing contracts were cancelled in anticipation of the Proposed Arctic Gas Sale. *See Note 16 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K.* The cancellation will have an impact on the Equity Affiliate-Russia reserves found on Table IV — Quantities of Oil and Natural Gas Reserves.

	Net Crude Oil and Condensate (MBbls)		
	Proved Developed	Proved Undeveloped	Total
Venezuela	41,172	42,439	83,611
Geoilbent	15,658	14,011	29,669
Arctic Gas(1)	2,484	18,479	20,963
Total	59,314	74,929	134,243

	Net Natural Gas (MMcf)		
	Proved Developed	Proved Undeveloped	Total
Arctic Gas(1)	21,292	186,718	208,010

(1) Based on 39 percent ownership not subject to restrictions as of December 31, 2001.

Estimates of commercially recoverable oil and natural gas reserves and of the future net cash flows derived therefrom 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 and 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 therefrom, 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 63 percent of our total proved reserves were undeveloped as of December 31, 2001.

Therefore, the following costs will likely vary from our estimates and such variances may be material:

- actual production;
- oil sales;
- 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;
- 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 sales and natural gas from proved reserves, 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, which is 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 and risks associated with the oil and natural gas industry. Discounted present value, no matter 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, 2001, we reported $365.7 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 lifting costs for the years ended December 31, 2001, 2000 and 1999. The presentation for Venezuela includes 100 percent of the production, without deduction for minority interest. Geoilbent (34 percent ownership) and Arctic Gas (39 percent, 29 percent and 24 percent ownership not subject to any sale or transfer restrictions at December 2001, 2000 and 1999, 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, 2001, 2000 and 1999 reflect results from Geoilbent for the twelve months ended September 30, 2001, 2000 and 1999, and from Arctic Gas for the twelve months ended September 30, 2001 and 2000.

	Years Ended December 31,		
	2001	2000	1999
Venezuela			
Net Crude Oil Production (Bbls)	9,777,516	9,364,088	9,666,958
Average Crude Oil Sales Price ($ per Bbl)	$12.52	$14.94	$9.21
Average Lifting Costs ($ per Bbl)	$ 4.30	$ 5.01	$4.02
Geoilbent			
Average Crude Oil Production (Bbls)	1,762,814	1,444,181	1,451,000
Average Crude Oil Sales Price ($ per Bbl)	$19.51	$18.54	$8.62
Average Lifting Costs ($ per Bbl)	$ 2.17	$ 2.31	$1.02
Arctic Gas			
Net Crude Oil Production (Bbls)	183,087	48,833	—
Average Crude Oil Sales Price ($ per Bbl)	$21.93	$18.20	—
Average Lifting Costs ($ per Bbl)	$ 7.42	$ 5.97	—

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;
- 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 addition, various federal, state, local and international laws and regulations covering 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. In any country in which we may do business, the oil and natural gas industry legislation and agency regulation is 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

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 and operating budgets to PDVSA for approval. Capital expenditures to comply with Venezuelan environmental regulations relating to the reinjection of natural gas in the field and water disposal were $0.1 million in 2001 and $1.1 million in 2000. 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 and Arctic Gas submit annual production and development plans, which include information necessary for permits and approvals for their 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. They also submit annual production targets and quarterly export nominations for oil pipeline transportation capacity to the Ministry of Fuel and Energy. Geoilbent and Arctic Gas are 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 and Arctic Gas 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.

Russian companies are subject to a statutory income tax rate of up to 35 percent and are subject to various other tax burdens and tariffs. Excise, pipeline and other tariffs and taxes continue to be levied on all oil producers and certain exporters, including an oil export tariff that decreased to $8.00 per ton (approximately $1.10 per barrel) from 23.4 Euros per ton (approximately $2.85 per barrel). We are unable to predict the impact of taxes, duties and other burdens in the future for our Russian operations.

Drilling, Acquisition and Finding Costs

From commencement of operations through December 31, 2001, we added, net of production and property sales, approximately 189.8 MMBOE of proved reserves through purchases of reserves-in-place, discoveries of oil and natural gas reserves, extensions of existing producing fields and revisions of previously estimated reserves, for which the finding costs were $2.34 per BOE. Our estimate of future development costs for our undeveloped proved reserves at December 31, 2001 was $1.96 per BOE. The estimated future development costs are based upon our anticipated cost of developing our non-producing proved reserves, which costs are calculated using historical costs for similar activities.

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):

- $44 million during 2001;
- $50 million during 2000; and
- $33 million during 1999.

We have drilled or participated in the drilling of wells as follows:

	Years Ended December 31,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Exploratory:						
Crude oil	—	—	—	—	—	—
Natural gas	—	—	—	—	—	—
Dry holes	—	—	—	—	3	1.60
Development:						
Crude oil	8	6.4	65	34.06	28	9.18
Natural gas	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Total	8	6.4	65	34.06	31	10.78
Average Depth of Wells (Feet)		6,043		7,048		9,092
Producing Wells (1):						
Crude Oil	274	169.9	268	163.6	181	108.0

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

At December 31, 2001, we participated in the drilling of 39 wells in Russia.

All of our drilling activities are conducted on a contract basis with independent drilling contractors. We do not directly own or operate any drilling equipment. Geoilbent does own components of the rigs it employs.

Acreage

The following table summarizes the developed and undeveloped acreage that we owned, leased or had under concession as of December 31, 2001:

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Venezuela	9,748	7,798	148,095	118,476
Russia(1)	42,457	14,339	2,109,358	704,002
China	—	—	7,470,080	7,470,080
United States	—	—	13,604	12,466
Total	52,205	22,137	9,741,137	8,305,024

(1) Russia includes 794,972 gross acres related to Arctic Gas, which is included based on a 39 percent ownership interest.

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 the 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 and facilities substantially greater than ours.

Environmental Regulation

We are subject to environmental regulations administered by foreign governments, their agencies, or other international organizations. 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 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, 2001, we had 19 full-time employees, augmented from time-to-time with independent consultants, as required. Benton-Vinccler had 174 employees, Geoilbent had 700 employees and Arctic Gas had 161 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 and Arctic Gas have obtained certain 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 covers 6.2 million acres in the South China Sea, with an option for another 1.0 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 Conoco Inc. 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, although certain proposed economic solutions currently under discussion would result in our interest being reduced.

As is customary in the oil and natural gas industry, we make a limited review of title to farm out acreage and to undeveloped U.S. oil and natural gas leases upon execution of the contracts and leases. Prior to the commencement of drilling operations, a thorough drillsite title examination is conducted and curative work is performed with respect to significant defects. We follow the practice of obtaining title opinions on our domestic producing properties and believe that we have satisfactory title to such properties in accordance with standards generally accepted in the oil and natural gas industry. Our oil and natural gas properties are subject to customary royalty interests, liens for current taxes, and other burdens which we believe do not materially interfere with the use of or affect the value of such properties.

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. "Tcf" means trillion cubic feet.

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

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.

Lifting Costs. "Lifting Costs" 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, severance and windfall profit taxes.

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.

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.

Royalty Interest. A "Royalty Interest" is an interest in an oil and gas property entitling the owner to a share of oil and natural gas production (or the proceeds of the sale thereof) free of the costs of production.

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 acres contain proved reserves.

Item 2. *Properties*

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 this office space has been subleased for rents that approximate our lease costs.

Item 3. *Legal Proceedings*

On February 17, 1998, the WRT Creditors Liquidation Trust ("WRT Trust") filed suit in the United States Bankruptcy Court, Western District of Louisiana against us and Benton Oil and Gas Company of Louisiana, a.k.a. Ventures Oil & Gas of Louisiana ("BOGLA"), seeking a determination that the sale by BOGLA to Tesla Resources Corporation ("Tesla"), a wholly owned subsidiary of WRT Energy Corporation, of certain West Cote Blanche Bay properties for $15.1 million, constituted a fraudulent conveyance under 11 U.S.C. Sections 544, 548 and 550 (the "Bankruptcy Code"). The alleged basis of the claim is that Tesla was insolvent at the time of its acquisition of the properties, and that it paid a price in excess of the fair value of the property. A trial commenced on May 1, 2000 that concluded at the end of August 2000, and post trial briefs were filed. In August 2001, a favorable decision was rendered in BOGLA's favor denying any and all relief to the WRT Trust. The WRT Trust has filed a Notice of Appeal with the Bankruptcy Court; however, we believe that the appeal will result in an outcome consistent with the court's prior decision.

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 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 and a consulting agreement with Mr. Benton pursuant to which we retained Mr. Benton as an independent contractor to perform certain services for us. During 2001, we paid Mr. Benton $116,833, and have paid a total of $536,545 from February 2000 through May 11, 2001 for services performed under the consulting agreement. On May 11, 2001, Mr. Benton and the Company entered into a settlement and release agreement under which the consulting agreement was terminated and Mr. Benton agreed to propose a plan of reorganization in his bankruptcy case that provides for the repayment of our loans to him. We currently continue to retain our security interest in Mr. Benton's 600,000 shares of our stock and in his stock options, and we have the right to vote the shares owned by him and to direct the exercise of his options. Repayment of our loans to Mr. Benton may be achieved through Mr. Benton's liquidation of certain real and personal property assets and a phased liquidation of stock resulting in Mr. Benton's exercise of his stock options. The amount that we eventually realize, and the timing of receipt of payments will depend upon the timing and results of the liquidation of Mr. Benton's assets. The amount of Mr. Benton's indebtedness to us is currently approximately $6.5 million. The consulting agreement provides that if we close the Proposed Arctic Gas Sale, Mr. Benton will be entitled to receive two percent of our net after-tax cash receipts, actually received by us in the U.S., resulting from the Proposed Arctic Gas Sale, excluding any repayment of indebtedness or advances by us to Arctic Gas. The consulting agreement further provides that under his proposed bankruptcy plan of reorganization, Mr. Benton will pay five percent of such amounts to us. Based upon information provided by Mr. Benton's bankruptcy counsel, we anticipate that under the bankruptcy plan of reorganization that Mr. Benton will propose, we will receive $1.7 million. This amount does not include the amounts that we will realize from the exercise of Mr. Benton's options and the subsequent sale of the resulting shares, nor does it include the net proceeds that we will receive from the sale of Mr. Benton's 600,000 shares of our stock.

In the normal course of our business, there are various other legal proceedings outstanding. In the opinion of management, these proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

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

During the three month period ended December 31, 2001, no matter was submitted to a vote of security holders.

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 April 29, 1997 under the symbol "BNO." As of December 31, 2001, there were 34,114,089 shares of Common Stock outstanding held of record by approximately 947 stockholders. The following table sets forth the high and low sales prices for our Common Stock reported by the NYSE.

Year	Quarter	High	Low
2000			
	First quarter	4.50	1.56
	Second quarter	3.56	2.00
	Third quarter	3.19	1.94
	Fourth quarter	2.75	1.38
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

On March 25, 2002, the last sales price for the Common Stock as reported by NYSE was $4.03 per share.

Our policy is to retain earnings to support the growth of our business. Accordingly, our Board of Directors has never declared cash dividends on our Common Stock, and our indentures currently restrict the declaration and payment of any cash dividends.

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, 2001. 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 based on a twelve-month period ending September 30. Accordingly, our results of operations for the years ended December 31, 2001, 2000, 1999 and 1998 reflect results from Geoilbent for the twelve months ended September 30, 2001, 2000, 1999 and 1998, and from Arctic Gas for the twelve months ended September 30, 2001, 2000 and 1999.

	Years Ended December 31,				
	2001	2000	1999	1998	1997
	(In thousands, except per share data)				
Statements of Operations:					
Total revenues	$122,386	$140,284	$ 89,060	$ 82,212	$154,033
Operating income (loss)	28,201	53,204	(22,525)	(210,066)	51,299
Income (loss) before minority interests	42,880	19,084	(34,216)	(201,413)	25,202
Net income (loss) per common share:					
Basic:					
Income (loss) before extraordinary items	$ 1.27	$ 0.54	$ (1.09)	$ (6.21)	$ 0.62
Extraordinary items	—	0.13	—	—	—
Net income (loss)	$ 1.27	$ 0.67	$ (1.09)	$ (6.21)	$ 0.62
Diluted:					
Income (loss) before extraordinary items	$ 1.27	$ 0.53	$ (1.09)	$ (6.21)	$ 0.59
Extraordinary items	—	0.13	—	—	—
Net income (loss)	$ 1.27	$ 0.66	$ (1.09)	$ (6.21)	$ 0.59
Weighted average common shares outstanding					
Basic	33,967	30,724	29,577	29,554	29,119
Diluted	34,008	30,890	29,577	29,554	30,834

	At December 31,				
	2001	2000	1999	1998	1997
	(In thousands, except per share data)				
Balance Sheet Data:					
Working capital (deficit)	$ (586)	$ 12,370	$ 32,093	$ 60,927	$174,759
Total assets	348,151	286,447	276,311	324,363	573,599
Long-term obligations, net of current position	221,583	213,000	264,575	280,002	280,016
Stockholders' equity (deficit) (1) (2)	67,623	12,904	(17,178)	12,989	197,732

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

(2) As discussed in Note 1 to the Financial Statements, in 1999 we changed our method of reporting our investment in Geoilbent to the equity method.

Item 7. *Management's Discussion and Analysis Of Financial Condition And Results Of Operations*

Management, Operational and Financial Restrictions

We have taken the necessary steps to strengthen management, enhance our financial flexibility, and improve our operations. In 2001, we completed the following:

- installed new senior management;
- redefined our strategic priorities to focus on value creation;
- initiated capital conservation steps and financial transactions, including the Proposed Arctic Gas Sale, designed to de-leverage the Company and improve our cash flow for reinvestment;
- undertook a comprehensive study of our core Venezuelan asset, which focused on enhancing the value of its production;
- pursued additional financing to accelerate the commercial development of our Russian assets;
- built the Tucupita pipeline in Venezuela to reduce transportation costs;
- sought and obtained relief from certain restrictive provisions of our debt instruments;
- reduced our corporate overhead, moved our headquarters to Houston and transferred engineering, geological and geophysical activities to its overseas offices; and
- proposed a change in our name to Harvest Natural Resources, Inc.

We continue to explore means by which to maximize stockholder value.

On February 27, 2002, we entered into a Sale and Purchase Agreement ("Proposed Arctic Gas Sale") to sell our entire 68 percent stock ownership interest in Arctic Gas Company to a nominee of the Yukos Oil Company for $190 million. We will also receive approximately $30 million as repayment of intercompany loans owed to us by Arctic Gas. We intend to use a portion of the net proceeds to retire all of the $108 million outstanding 11⅝ percent senior notes in accordance with their terms. We intend to use any remaining net proceeds and cash received from the repayment of loans to further reduce debt from time to time, accelerate the strategic growth of its assets in Venezuela and Russia and for general corporate purposes. On March 22, 2002, we were notified that the Transaction had received the requisite consents from the Russian Ministry for Antimonopoly Policy and Support for Entrepreneurship. On March 28, 2002, we received the first payment ($120.0 million) of the Proposed Arctic Gas Sale proceeds. However, in the event that the Transaction does not close, we will be required to review additional strategic alternatives to repay the $108 million of 11⅝ percent senior notes due in May 2003, including, but not limited to, selling all or part of our existing assets in Venezuela and Russia, restructuring our debt, some combination thereof, or the selling of the Company. However, no assurance can be given that any of these steps can be successfully completed or that we ultimately will determine that any of the steps should be taken. The Pro Forma adjustments reflect a net gain after tax of $92.0 million, which utilizes our $136.0 million net operating loss. The cash available after tax is used to purchase the $108.0 million 11⅝ percent senior notes at par.

In the event the Proposed Arctic Gas Sale closes, the Supplemental Unaudited Pro Forma Condensed Balance Sheet as of December 31, 2001 shown below illustrates the impact to the Company.

Benton Oil and Gas Company and Subsidiaries

Supplemental Unaudited Pro Forma Condensed Balance Sheet

	As of December 31, 2001	Pro Forma Adjustments(1)	Pro Forma
	(Amounts in thousands)		
Assets:			
Cash	$ 9,024	$ 82,587	$ 91,611
Investment in Arctic Gas	24,405	(24,405)	—
Intercompany Receivable	28,829	(28,829)	—
Deferred Tax Asset	57,700	(44,398)	13,302
Other Assets	228,193		228,193
Total	$348,151		$333,106
Liabilities and Stockholders' Equity:			
Liabilities	$ 58,945		$ 58,945
Long-Term Debt	221,583	(108,000)	113,583
Total Stockholders' Equity	67,623	92,955	160,578
Total	$348,151		$333,106
Debt to Total Equity	77%		41%

(1) To record gain on sale of 68 percent interest in Arctic Gas Company, to repay intercompany debt and to repay $108 million of 11⅝ percent senior notes.

See Note 16 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K.

As part of the Proposed Arctic Gas Sale, we have arranged a credit facility of up to $100 million for Arctic Gas. In the event that the Proposed Arctic Gas Sale does not close, we will request Arctic Gas to immediately repay this facility.

We possess significant producing properties in Venezuela, which we believe have yet to be optimized, and valuable unexploited acreage in both Venezuela and Russia. We believe the eleven new wells drilled in the South Tarasovskoye Field since July 2001 may significantly increase the value of our Geoilbent properties. In December 2001 and January 2002, we spudded the first two wells in our seven well Tucupita field program in Venezuela. We are evaluating the construction of additional processing and handling facilities and are in discussions with PDVSA to negotiate a sales contract that will allow for the first-time sale of natural gas in Venezuela by our affiliate.

In May 2001, we initiated a process intended to effectively extend the maturity of the senior notes due May 1, 2003 by exchanging new 13.125 percent senior notes due December 2007 plus warrants to purchase shares of our common stock for each of the 2003 Notes. The exchange offer was withdrawn in July 2001. However, in August 2001, we solicited and received the requisite consents from the holders of both the 2003 Notes and the 2007 Notes to amend certain covenants in the indentures governing the notes to enable Arctic Gas Company to incur nonrecourse debt of up to $77 million to fund its oil and gas development program. As an incentive to consent, we paid each noteholder an amount in cash equal to $2.50 per $1,000 principal amount of notes held for which executed consents were received. The total amount of consent fees paid to the consenting noteholders was $0.3 million, which has been included in general and administrative expenses.

In June 2001, we implemented a plan designed to reduce overall general and administrative costs, including exploration overhead, at our corporate headquarters and to transfer management oversight of geological and geophysical activities to our overseas offices in Maturin, Venezuela and in Western Siberia and

Moscow, Russia. The reduction in general and administrative costs was accomplished by reducing our headquarters staff and relocating our headquarters to Houston, Texas from Carpinteria, California. For 2001, we recorded non-recurring items of $11.4 million, $5.7 million of which are included in general and administrative expenses, $1.7 million of which are included in depletion, depreciation and amortization, $3.2 million in operating expenses and $0.8 million in taxes other than income. The general and administrative expenses include $2.2 million on the failed debt exchange, $2.2 million for severance and termination benefits for 33 employees, $1.1 million for lease relinquishment expenses, and $0.2 million for relocation costs to Houston. Depletion, depreciation and amortization included $0.9 million for the reduction in the carrying value of fixed assets that were not transferred to Houston and $0.8 million loss on subleasing the former Carpinteria headquarters. All expenses were paid by December 31, 2001.

Geoilbent has reduced its 2002 capital budget to approximately $16.6 million, of which $2.7 million is for the North Gubkinskoye Field, $9.7 million is for the South Tarakovskoye Field, $2.2 million is to carry out seismic and related exploration activity and $2.0 million is for natural gas plant economic, technical and feasibility studies. Geoilbent's 2002 operating budget includes $16 million for principal payments on the loan facility. In addition, Geoilbent had outstanding accounts payable of $26.6 million as of December 31, 2001, primarily to contractors and vendors for drilling and construction services.

Although Geoilbent's reduced capital expenditure budget may help to alleviate any shortfall of funds available to make payments to the banks and its creditors as those payments come due, it is uncertain that Geoilbent's cash flow from operations will be sufficient to do so, and it may be necessary for Geoilbent to obtain capital contributions from its partners, including the Company, to have sufficient funds to make these payments on a timely basis. Although the Company may consider making such a capital contribution, there can be no assurances that the Company will do so, nor can there be any assurances that Geoilbent's other partner will be willing or able to do so. Under Russian law, a creditor can force a company into involuntary bankruptcy if the company's payments have been due for more than 90 days.

At the annual meeting of our shareholders to be held on May 14, 2002, our stockholders will vote on a proposal to change the name of our company to "Harvest Natural Resources, Inc."

Operating Strategy

Our business strategy supports the steady investment, prudent risk management and timely harvest of large hydrocarbon resources for attractive values. 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.

During 2001, our operating strategy was necessarily focused on improving the efficiency and efficacies of our current operations in both Venezuela and Russia. Over the years, we have benefited from the significant capital commitment made to these areas, but have suffered financially from sub-optimal operating, contracting and risk management practices which, for the most part, have been or are currently in the process of being significantly improved. In Venezuela, we implemented new development and production plans at Benton-Vinccler following an eight-month suspension of drilling and an extensive reservoir study, which resulted in increased production, lower operating costs, and added confidence in our future drilling plans to extend the life and value of the field. We have also streamlined decision making, improved internal controls and implemented industry standard techniques to mitigate geologic, operating, financial and political risks attendant with doing business in Venezuela.

In Russia, where we are a minority holder in Geoilbent, we are attempting to pursue a similar course, with the help of other interest owners, in order to improve operations and extend the life of the field, lower operating costs and enhance financial results. These assets represent significant potential value for us, but remain subject to sub-optimal operating conditions while our lack of majority control over its operations could inhibit our ability to implement necessary changes in management, operations or financing matters.

In both Venezuela and Russia, and in other counties around the world, the development of local markets for natural gas represents a significant opportunity for us. However, the development of these markets, in large part, depends upon substantial capital investment by third parties in the infrastructure needed to produce, gather, treat, transport, store and convert natural gas into marketable products. While this investment is beginning to materialize in many of these markets, it will take many years, in some instances, to place such assets into service. We are well positioned to benefit from the emergence of new regional gas markets in proximity to our reserves.

Our long-term strategy is to identify, access and exploit large resources of hydrocarbons in underexploited areas around the world that can be developed at low overall finding costs, produced at low operating costs and converted into proved reserves, production and value. While our success is dependent upon many factors both within and outside of our control, in order to achieve this strategy, we must:

- continue to improve our financial flexibility and financing strategies;
- exploit our core assets in Venezuela and Russia; and
- seek and exploit new oil and natural gas resources in our core areas.

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 exploration and development activities only in areas of known, proven hydrocarbons.
- *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.

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 reflect the results of Geoilbent and Arctic Gas for the twelve months ended September 30, 2001, 2000 and 1999.

You should read the following discussion of the results of operations for each of the years in the three year period ended December 31, 2001 and the financial condition as of December 31, 2001 and 2000 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 oil and natural gas sales in the following table:

	Years Ended December 31,		
	2001	2000	1999
Operating Expenses(1)	32%	34%	44%
Depletion, Depreciation and Amortization(2)	19	12	19
General and Administrative(3)	12	12	29
Taxes Other Than on Income(4)	4	3	4
Interest	20	21	33

2001 non-recurring costs excluded in millions:

(1) \$3.2 in natural gas fuel use charges for the period of 1997 through 2000 before Venezuelan tax and minority interest is included.

(2) \$1.7 reduction in carrying value of California office lease.

(3) \$2.3 in debt exchange costs; \$1.1 California office lease relinquishment; \$0.2 relocation to Houston; \$2.1 severance and termination payments.

(4) \$0.8 in municipal tax adjustments before Venezuelan tax and minority interest.

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, C.A. 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. *See Note 16 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K.* 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. Additionally, 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 may be contractual obligations or legal impediments such as currency controls to receiving dividends or distributions from our subsidiaries.

Debt Reduction and Restructuring Program. We currently have significant debt principal obligations payable in 2003 ($108 million) and 2007 ($105 million). As described below, we have reduced our obligations due in 2003 by $17 million since September 10, 2000. We further intend to retire the 2003 ($108 million) obligation with the proceeds from the Proposed Arctic Gas Sale. However, in the event we do not close the Proposed Arctic Gas Sale, we will be required to review additional strategic alternatives to repay the $108 million of 11⅝ percent senior notes due May 2003. We intend to pursue additional open market debt purchases of the obligations due in 2007 to further reduce debt.

Working Capital. Our capital resources and liquidity are affected by the timing of our semiannual interest payments of approximately $11.2 million each May 1 and November 1 and by 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. In October 2000, an uncommitted short-term working capital facility of 8 billion Bolivars (approximately $8 million currently) was made available to Benton-Vinccler by a Venezuelan commercial bank. The credit facility bears interest at fixed rates for 30-day periods, is guaranteed by us and contains no restrictive or financial ratio covenants. We believe that similar arrangements will be available to us in future quarters. At December 31, 2001, there was no outstanding balance. In February 2002, the Venezuelan Bolivar was allowed to float against the U.S. dollar. While the long-term impact of this action is uncertain, the short-term implication may be difficulty in purchasing U.S. dollars with Bolivars and reducing U.S. dollar equivalent amounts of Benton-Vinccler's short-term working capital facility. We are negotiating with a bank to increase the Bolivar denominated short-term working capital facility to approximately $12 million U.S. dollar equivalent. We do not expect this action to have a material impact on Benton-Vinccler's operations.

The Proposed Arctic Gas Sale can provide the additional funds for both the service of our debt and the development of our assets. However, in the event we do not close the Proposed Arctic Gas Sale, we will be required to review additional strategic alternatives to repay the $108 million of 11⅝ percent senior notes due May 2003. We continue to develop sources of additional capital and/or reduce or reschedule our cash requirements by various techniques including, but not limited to, the pursuit of one or more of the following alternatives:

- restructure the existing debt;
- manage the scope and timing of our capital expenditures, substantially all of which are within our discretion;
- form joint ventures or alliances with financial or other industry partners;

There can be no assurance that any of the above alternatives, or some combination thereof, will be available or, if available, will be on terms acceptable to us.

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,		
	2001	2000	1999
		(In thousands)	
Net cash provided by (used in) operating activities	$ 36,608	$ 51,763	$ (1,392)
Net cash provided by (used in) investing activities	(48,012)	(28,772)	20,989
Net cash provided by (used in) financing activities	5,296	(29,006)	(15,648)
Net increase (decrease) in cash	$ (6,108)	$ (6,015)	$ 3,949

At December 31, 2001, we had current assets of $43.5 million and current liabilities of $44.1 million, resulting in negative working capital of $0.6 million and a negative current ratio. This compares with our working capital of $12.3 million and a current ratio of 1.24:1 at December 31, 2000. The decrease in working capital of $13.0 million was primarily due to lower prices and additional investments in and advances to Arctic Gas Company during the year ended December 31, 2001.

Geoilbent has reduced its 2002 capital budget to approximately $16.6 million, of which $2.7 million is for the North Gubkinskoye Field, $9.7 million is for the South Tarakovskoye Field, $2.2 million is to carry out seismic and related exploration activity and $2.0 million is for natural gas plant economic, technical and feasibility studies. Geoilbent's 2002 operating budget includes $16 million for principal payments on the loan facility. In addition, Geoilbent had outstanding accounts payable of $26.6 million as of December 31, 2001, primarily to contractors and vendors for drilling and construction services.

Although Geoilbent's reduced capital expenditure budget may help to alleviate any shortfall of funds available to make payments to the banks and its creditors as those payments come due, it is uncertain that Geoilbent's cash flow from operations will be sufficient to do so, and it may be necessary for Geoilbent to obtain capital contributions from its partners, including the Company, to have sufficient funds to make these payments on a timely basis. Although the Company may consider making such a capital contribution, there can be no assurances that the Company will do so, nor can there be any assurances that Geoilbent's other partner will be willing or able to do so. Under Russian law, a creditor can force a company into involuntary bankruptcy if the company's payments have been due for more than 90 days.

Cash Flow from Operating Activities. During the year ended December 31, 2001 and 2000, net cash provided by (used in) operating activities was approximately $36.6 million and $51.8 million, respectively. Cash flow from operating activities decreased by $15.2 million during the year ended December 31, 2001 compared with 2000. This was primarily due to collections of accrued oil revenues.

Cash Flow from Investing Activities. During the year ended December 31, 2001 and 2000, we had drilling and production related capital expenditures of approximately $43.4 million and $57.2 million, respectively. Of the 2001 expenditures, $35.7 million was attributable to the development of the South Monagas Unit and $7.7 million was attributable to the Delta Centro Block in Venezuela.

In addition, during the year ended December 31, 2001, we increased our investment in Arctic Gas by $16.8 million.

We expect capital expenditures of approximately $29.1 million at the South Monagas Unit during the next 12 months. The timing and size of the investments for the South Monagas Unit are substantially at our discretion. We anticipate that Geoilbent will continue to fund its expenditures through its own cash flow, credit facilities and potentially a shareholder contribution. Our remaining capital commitments worldwide are relatively minimal and are substantially at our discretion. We will also be required to make interest payments of approximately $11.2 million related to our outstanding senior notes in April 2002 and $4.9 million in November 2002, assuming we close the Proposed Arctic Gas Sale and retire $108 million of the 11⅝ percent senior notes prior to November 2002.

We continue to assess production levels and commodity prices in conjunction with our capital resources and liquidity requirements. The results from the new wells drilled in the Tucupita Field in Venezuela under the alliance agreements with Schlumberger indicate that the reservoir formation quality is as expected, but may be sensitive to drilling and completion practices.

Cash Flow from Financing Activities. In May 1996, we issued $125 million in 11⅝ percent senior unsecured notes due May 1, 2003, of which we repurchased $17 million at their discounted value in September and November 2000. The notes were repurchased with the issuance of 4.2 million common shares and cash of $3.5 million plus accrued interest. In November 1997, we issued $115 million in 9⅜ percent senior unsecured notes due November 1, 2007, of which we subsequently repurchased $10 million at their par value for cash. Interest on all of the 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, 2001, we were in compliance with all covenants of the indentures.

We have a deferred drilling and completion obligations under our alliance with Schlumberger and with Flint South America, Inc as well as a lease for our Houston office space. The following table summarizes our contractual obligations at December 31, 2002.

	Payments Due by Period				
Contractual Obligation	Total	Less than 1 Year	1-2 Years	3-4 Years	After 4 Years
			(In thousands)		
Long Term Debt	$224,015	$ 2,432	$113,544	$2,432	$105,607
Deferred Drilling and Completion	8,871	8,871			
Building Lease	396	132	264		
Total	$233,282	$11,435	$113,808	$2,432	$105,607

While we can give you no assurance, we currently believe that our cash flow from operations, supplemented by borrowings and asset sales if required, 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 price levels, production and the availability of short-term working capital facilities of up to $12 million currently during the time periods between the submission of quarterly invoices to PDVSA by Benton-Vinccler and the subsequent payments of these invoices by PDVSA and other financial alternatives. Actual results could be materially affected if there is a significant decrease in either price or production levels related to the South Monagas Unit. 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 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.

However, we currently have significant debt obligations payable in May 2003 and November 2007 of $108 million and $105 million, respectively. Our ability to meet our debt obligations and to reduce our level of debt depends on the successful implementation of our strategic objectives, in particular the timely close of the Proposed Arctic Gas Sale. While we believe the Proposed Arctic Gas Sale will be consummated, there can be no assurance that the transaction will close.

In the event that the Transaction does not close, we will be required to review additional strategic alternatives to repay the $108 million due in May 2003 in debt, including but not limited to, selling all or part of our existing assets in Venezuela and Russia, restructuring our debt, some combination thereof, or selling the Company. However, no assurances can be given that any of these steps can be successfully completed or that we ultimately will determine that any of the steps should be taken.

Years Ended December 31, 2000 and 1999

Our results of operations for the year ended December 31, 2000 primarily reflected the results for Benton-Vinccler, C.A. in Venezuela, which accounted for substantially 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 57 percent higher in 2000 compared with 1999. Realized fees per barrel increased 62 percent (from $9.21 in 1999 to $14.94 in 2000) and oil sales quantities decreased 3 percent (from 9.7 MMBbls of oil in 1999 to 9.4 MMBbls of oil in 2000). Our operating expenses from the South Monagas Unit increased 21 percent primarily due to increased chemical treatment, electricity and natural gas compression station maintenance and operating costs, partially offset by reduced salaries and material costs.

Our revenues increased $51.2 million, or 57 percent, during the year ended December 31, 2000 compared with 1999. 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, 2000 from Venezuela were 9.4 MMBbls compared to 9.7 MMBbls for the year ended December 31, 1999. The decrease in sales quantities of 302,890 Bbls, or 3 percent, was due primarily to production declines beginning in 1999 resulting from the curtailment of the Venezuelan development drilling program. Venezuelan production declined to 24,300 Bbls of oil per day by the end of 1999. Production increased to 28,000 Bbls or oil per day by the end of 2000 as a result of drilling 26 additional wells during the year. Prices for crude oil averaged $14.94 per Bbl (pursuant to terms of an operating service agreement) from Venezuela compared with $9.21 per Bbl for 1999.

Our operating expenses increased $8.0 million, or 20 percent, during the year ended December 31, 2000 compared to the year ended December 31, 1999. This was primarily due to increased chemical treatment, electricity and natural gas compression station maintenance and operating costs, which were partially offset by reduced salaries and material costs at the South Monagas Unit in Venezuela. Depletion, depreciation and amortization increased $0.7 million, or 4 percent, during the year ended December 31, 2000 compared with 1999 primarily due to decreased proved reserves and increased future development costs at the South Monagas Unit. Depletion expense per barrel of oil produced from Venezuela during 2000 was $1.68 compared with $1.53 during 1999. We recognized write-downs of capitalized costs of $1.3 million associated with exploration activities in Jordan and California during the year ended December 31, 2000 compared with $25.9 million associated with exploration activities in California, China, Senegal and Jordan during the year ended December 31, 1999. General and administrative expenses decreased $9.3 million, or 36 percent, during the year ended December 31, 2000 compared with 1999. This was primarily due to the following:

- our reduction in workforce and related restructuring costs in 1999;
- the write-off of the joint interest receivable due from Molino Energy at December 31, 1999 associated with the California Leases; and
- an allowance for doubtful accounts in 1999, related to amounts owed to us by our former Chief Executive Officer *(see Note 13 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K of Notes to the Consolidated Financial Statements)*.

Taxes other than on income increased $0.6 million, or 16 percent, during the year ended December 31, 2000 compared with 1999. This was primarily due to increased Venezuelan municipal taxes, which are a function of oil revenues.

Investment income and other decreased $0.4 million, or 4 percent, during the year ended December 31, 2000 compared with 1999. This was due to lower average cash and marketable securities balances. Interest expense decreased $0.2 million, or 1 percent, during the year ended December 31, 2000 compared with 1999. This was primarily due to the reduction of debt balances, partially offset by a reduction of capitalized interest expense. Net gain on exchange rates decreased $0.7 million, or 70 percent for the year ended December 31, 2000 compared with 1999. This was due to changes in the value of the Bolivar. We realized income before income taxes and minority interest of $33.1 million during the year ended December 31, 2000 compared with a loss of $41.7 million in 1999. This resulted in increased income tax expense of $21.5 million. The effective tax rate of 42 percent varies from the U.S. statutory rate of 35 percent primarily because income taxes are paid on profitable operations in foreign jurisdictions and no benefit is provided for net operating losses generated in the U.S. The income attributable to the minority interest increased $7.0 million for the year ended December 31, 2000 compared to 1999. This was primarily due to the increased profitability of Benton-Vinccler.

Equity in net earnings of affiliated companies increased $2.4 million, or 83 percent, during the year ended December 31, 2000 compared with 1999. This was primarily due to the increased income from Geoilbent. Our share of revenues from Geoilbent was $25.2 million for the year ended September 30, 2000 compared with revenues of $11.1 million for 1999. The increase of $14.1 million, or 127 percent, was due to significantly higher world crude oil prices partially offset by lower sales quantities. Prices for Geoilbent's crude oil averaged $17.45 per Bbl during the year ended September 30, 2000 compared with $7.68 per Bbl for the year ended September 30, 1999. Our share of Geoilbent oil sales quantities decreased by 6,819 Bbls, or 0.5 percent, from 1,451,000 Bbls sold during the year ended September 30, 1999 to 1,444,181 Bbls sold during the year ended September 30, 2000. The decrease in oil sales was due primarily to the temporary interruption of production in early 2000 resulting from an accident during the period that affected certain production facilities. We recorded extraordinary income of $4.0 million during the year ended December 31, 2000 related to the repurchase at a discount of $17 million of our senior unsecured notes due in 2003. We exchanged a total of 4.2 million shares of our common stock with a market value of $9.3 million and cash of $3.5 million for $17 million in notes. We also wrote-off $0.2 million in unamortized loan fees related to the notes.

Effects of Changing Prices, Foreign Exchange Rates and Inflation

Our results of operations and cash flow are affected by changing oil prices. However, our South Monagas Unit oil sales are based on a fee adjusted quarterly by the percentage change of a basket of crude oil prices instead of by absolute dollar changes. This dampens both any upward and downward effects of changing prices on our Venezuelan oil sales and cash flows. If the price of oil increases, there could be an increase in our cost for drilling and related services because of increased demand, as well as an increase in oil sales. Fluctuations in oil and natural gas prices may affect our total planned development activities and capital expenditure program. There are presently no restrictions in either Venezuela or Russia that restrict converting U.S. dollars into local currency. However, from June 1994 through April 1996, Venezuela implemented exchange controls which significantly limited the ability to convert local currency into U.S. dollars. Because payments to Benton-

Vinccler are made in U.S. dollars into its United States bank account, and Benton-Vinccler was not subject to regulations requiring the conversion or repatriation of those dollars back into Venezuela, the exchange controls did not have a material adverse effect on us or Benton-Vinccler. Currently, there are no exchange controls in Venezuela or Russia that restrict conversion of local currency into U.S. dollars for routine business operations, such as the payments of invoices, debt obligations and dividends.

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, 2001, our net foreign exchange gain attributable to our Venezuelan operation was $0.7 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.

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 price controls, tax and other laws relating to the petroleum industry, by changes in such laws and by changing administrative regulations and the interpretations and application of such rules and regulations. In addition, various federal, state, local and international laws and regulations covering 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 results.

Significant Accounting Policies

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. The operating service agreement provides for Benton-Vinccler to receive an operating fee for each barrel of crude oil delivered. It also provides 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.

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. 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. 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. 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.

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.

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.

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statements of Financial Accounting Standards No. 141 "Business Combinations" ("SFAS 141") and No. 142 "Goodwill and Other Intangible Assets" ("SFAS 142"). SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for under the purchase method. For all business combinations for which the date of acquisition is after June 30, 2001, SFAS 141 also establishes specific criteria for the recognition of intangible assets separately from goodwill. SFAS 141 also requires unallocated negative goodwill (in a case where the purchase price is less than fair market value of the acquired assets) to be written off immediately as an extraordinary gain, rather than deferred and amortized. SFAS 142 changes the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: 1) goodwill and intangible assets with indefinite lives will no longer be amortized; 2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and 3) the amortization period for intangible assets with finite lives will no longer be limited to 40 years. In August 2001, the FASB also approved SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"). SFAS 144 replaces SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." The new accounting model for long-lived assets to be disposed of by sale applies to all long-lived assets, including discontinued operations, and replaces the provisions of APB Opinion No. 30, "Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business", for the disposal of segments of a business. SFAS 144 requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are effective for financial statements issued for fiscal years beginning after December 15, 2001 and, generally are to be applied prospectively. These statements are not expected to have a material impact on our financial position, results of operations, or cash flows.

In June 2001, the FASB also approved for issuance SFAS 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets such as wells and production facilities. SFAS 143 guidance covers (1) the timing of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long- lived asset and subsequently allocated to expense using a systematic and rational method. The Company will adopt the statement effective no later than January 1, 2003, as required. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle. At this time, the Company cannot reasonably estimate the effect of the adoption of this statement on its financial position, results of operations or cash flows.

Cost Reductions

In an effort to reduce general and administrative expenses, we closed our Carpinteria, California office. We completed our relocation to Houston, Texas. The technical capabilities of the field offices managing the key foreign assets have been enhanced, particularly in Venezuela. Accountability has been transferred our offices in Maturin, Venezuela and Western Siberia, Russia. Venezuelan operating costs were reviewed and reduced to $4.05 per Bbl before a non-recurring charge for fuel gas use for the period of 1997 through 2000 compared with average operating cost of $5.01 per Bbl in 2000. We expect operating costs to average between $3.00 and $3.50 per Bbl sold in 2002.

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.

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 decreased from approximately $14.94 per Bbl for the year ended December 31, 2000 to $12.52 per Bbl for the year ended December 31, 2001. During the same period, the average price we received for oil in Russia increased from $18.54 per Bbl to $19.51 per Bbl. Our Venezuelan oil sales are based on a fee adjusted quarterly by the percentage change of a basket of crude oil prices instead of by absolute dollar changes, which dampens both any upward and downward effects of changing prices on our Venezuelan oil sales and cash flows. 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, particularly those in Russia and the Middle East; and

- overall economic conditions.

New York Stock Exchange Delisting. In October 2001, we received a letter from the New York Stock Exchange ("NYSE") notifying us that we have fallen below the continued listing standards 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 as of September 30, 2001, was $16.0 million. In accordance with the NYSE's rules, we submitted a plan to the NYSE in December detailing how we expect 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. These initiatives include continued cost reductions, production enhancements, selling all or part of our assets in Venezuela and/or Russia, restructuring the debt or some combination of these alternatives. Failure to achieve the financial and operational goals may result in being subject to NYSE trading suspension at the point the initiative or goal is not met. As a result of a delisting, an investor will find it more difficult to dispose or obtain quotations or market value of our common stock, which may adversely affect the marketability of our common stock. However, given the successful execution of our strategic plan referenced above, we are optimistic that we will be able to meet the NYSE requirements in the future and consequently, do not expect our stock to be delisted. As of December 31, 2001, our stockholders' equity was $67.6 million, and as of March 25, 2002 our market capitalization was in excess of $138 million.

The Proposed Arctic Gas Sale May Not Close. While we can give you no assurance, we currently believe that our cash flow from operations, supplemented by borrowings and asset sales if required, 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 price levels, production and the availability of short-term working capital facilities of up to $12 million currently during the time periods between the submission of quarterly invoices to PDVSA by Benton-Vinccler and the subsequent payments of these invoices by PDVSA and other financial alternatives. Actual results could be materially affected if there is a significant decrease in either price or production levels related to the South Monagas Unit. 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 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.

However, we currently have significant debt obligations payable in May 2003 and November 2007 of $108 million and $105 million, respectively. Our ability to meet our debt obligations and to reduce our level of debt depends on the successful implementation of our strategic objectives, in particular the timely closing of the Proposed Arctic Gas Sale. While we believe the Proposed Arctic Gas Sale will be consummated, there can be no assurance that the transaction will close.

In the event that the Proposed Arctic Gas Sale does not close, we will be required to review additional strategic alternatives to repay the $108 million in debt, including but not limited to, selling all or part of our existing assets in Venezuela and Russia, restructuring our debt, some combination thereof, or selling the Company. However, no assurances can be given that any of these steps can be successfully completed or that we ultimately will determine that any of the steps should be taken.

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, 2001, approximately 63 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 consumption 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.

Leverage Materially Affects Our Operations. Even if the Proposed Arctic Gas Sale is completed, we remain leveraged. As of December 31, 2001, our long-term debt was $221.6 million. Our long-term debt represented 77 percent of our total capitalization at December 31, 2001. If the Proposed Arctic Gas Sale closes, our debt level will be reduced to 41 percent of our total capitalization. Our level of debt affects 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 high 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.

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. In 1998, we recorded after-tax write-downs of $158.5 million ($187.8 million pre-tax). Since 1998, we recorded no ceiling limitation write-downs. We cannot assure you that we will not experience ceiling limitation write-downs in the future. We perform quarterly cost center ceiling tests of our oil and gas properties. No ceiling test write-downs were required in 2001.

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; and
- shortages in experienced labor or shortages or delays in the delivery of equipment.

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, blowouts, 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.

Our Concentration of Assets Increases Our Exposure to Production Declines. During 2001, the production from the South Monagas Unit in Venezuela represented approximately 100 percent 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. Venezuela is a member of the Organization of Petroleum Exporting Countries, which has collectively reduced crude oil exports in an attempt to increase crude oil prices. We have been required to curtail sales to PDVSA from time to time due to their insufficient crude oil storage capacity. We cannot be assured that our sales to PDVSA will not be curtailed in the future in the same manner. In March 2002, the managers of PDVSA are challenging the replacement of their senior management by the President of Venezuela. The implications of this unrest are uncertain at this date.

Our International Operations May be Adversely Affected by Currency Fluctuations and Economic and Political Developments. We have substantially all of our operations in Venezuela and Russia. The expenses of such operations are payable in local currency while most of the revenue from oil sales is paid in U.S. dollars. As a result, our operations are subject to the risk of fluctuations in the relative value of the Bolivar, Ruble and U.S. dollar. Our foreign operations may also be adversely affected by political and economic developments, royalty and tax increases and other laws or policies in these countries, as well as U.S. policies affecting trade, taxation and investment in other countries.

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 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 supplies of oil and natural gas, these agencies have restricted the rates of flow of oil and natural gas wells below actual production capacity. In addition, our operations are subject to taxation policies, that in Russia have changed significantly. We cannot predict the ultimate cost of compliance with these requirements or their effect on our operations.

Foreign Currency Risk. We have significant operations outside of the United States, principally in Venezuela and Russia. Both Venezuela and Russia have historically been considered highly inflationary economies. Operations in those countries 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 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. In February 2002, Venezuela elected to float the Bolivar, resulting in approximately a 20 percent devaluation. Our Venezuelan receipts are denominated in U.S. dollars, while most expenditures are in Bolivars. Management does not expect the devaluation to have a material impact.

Foreign Operations Risk. 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 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 the Company's international operations. Venezuela has had labor strikes and demonstrations in 2001 and the first quarter of 2002. The implications and results of this unrest are uncertain at this time. We are dependent on cash flows received from Benton-Vinccler to fund our U.S. expenses, including interest expenses for the $108 million of 11⅝ percent senior notes and the $105 million of 9⅜ percent senior notes. If Venezuela imposed currency restrictions which prohibited our receipt of funds from Benton-Vinccler, our ability to meet our interest payments would be adversely affected. 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. To date, our international operations have not been materially affected by these risks.

Minority Ownership in Geoilbent. We own 34 percent in Geoilbent. We are reviewing ways to improve the operations, but we are a minority partner and therefore may not be able to fully influence changes in the daily operations, if indicated by our review.

Geoilbent has reduced its 2002 capital budget to approximately $16.6 million, of which $2.7 million is for the North Gubkinskoye Field, $9.7 million is for the South Tarakovskoye Field, $2.2 million is to carry out seismic and related exploration activity and $2.0 million is for natural gas plant economic, technical and feasibility studies. Geoilbent's 2002 operating budget includes $16 million for principal payments on the loan facility. In addition, Geoilbent had outstanding accounts payable of $26.6 million as of December 31, 2001, primarily to contractors and vendors for drilling and construction services.

Although Geoilbent's reduced capital expenditure budget may help to alleviate any shortfall of funds available to make payments to the banks and its creditors as those payments come due, it is uncertain that Geoilbent's cash flow from operations will be sufficient to do so, and it may be necessary for Geoilbent to obtain capital contributions from its partners, including the Company, to have sufficient funds to make these payments on a timely basis. Although the Company may consider making such a capital contribution, there can be no assurances that the Company will do so, nor can there be any assurances that Geoilbent's other partner will be willing or able to do so. Under Russian law, a creditor can force a company into involuntary bankruptcy if the company's payments have been due for more than 90 days.

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 and foreign exchange, as discussed below.

Oil and Natural Gas Prices

As an independent oil and natural gas 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 condensate. 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 and natural gas production have been volatile and unpredictable, and such volatility is expected to continue. This volatility is demonstrated by the average realizations in Venezuela, which declined from $10.01 per Bbl in 1997 to $6.75 in 1998 and increased to $14.94 in 2000, then back down to $12.52 in 2001. Based on our budgeted production and costs, we will require an average realization in Venezuela of approximately $8.64 (relates to $18 West Texas Intermediate benchmark price) per Bbl in 2002 in order to break-even on income from consolidated companies before our equity in earnings from affiliated companies. We have not hedged our oil production since 1996. While hedging limits the downside risk of adverse price movements, it may also limit future revenues from favorable price movements. 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.

Interest Rates

Total long-term debt at December 31, 2001, consisted of $213 million of fixed-rate senior unsecured notes maturing in 2003 ($108 million) and 2007 ($105 million) on debt. A hypothetical 10 percent adverse change in the floating rate would not have had a material affect on our results of operations for the year ended December 31, 2001.

Foreign Exchange

Our operations are located primarily outside of the United States. In particular, our current oil producing operations are located in Venezuela and Russia, countries which have had recent histories of significant inflation and devaluation. For the Venezuelan operations, oil 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 the Russian operations, a majority of the oil sales are received in U.S. dollars; 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.

Item 8. *Financial Statements and Supplemental Data*

The information required by this item is included herein on pages S-1 through S-39.

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

No information is required to be reported under this item.

PART III

Item 10. *Directors and Executive Officers of the Registrant*

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Item 11. *Executive Compensation*

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

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Item 13. *Certain Relationships and Related Transactions*

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* 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 2002 Annual Meeting of Shareholders.

PART IV

Item 14. *Exhibits, Financial Statement Schedules and Reports on Form 8-K*

(a) 1. *Index to Financial Statements:*

2. *Consolidated Financial Statement Schedules:*

Schedule II — Valuation and Qualifying Accounts

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)).

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 Benton Oil and Gas Company 1991-1992 Stock Option Plan (Exhibit 10.14) (Previously filed as an exhibit to our S-1 Registration Statement (Registration No. 33-43662)).

10.3 Benton Oil and Gas Company Directors' Stock Option Plan (Exhibit 10.15) (Previously filed as an exhibit to our S-1 Registration Statement (Registration No. 33-43662)).

10.4 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)).

10.5 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)).

10.6 Indenture dated May 2, 1996 between Benton Oil and Gas Company and First Trust of New York, National Association, Trustee related to $125,000,000, 11⅝ percent Senior Notes Due 2003 (Incorporated by reference to Exhibit 4.1 to our S-4 Registration Statement filed June 17, 1996, SEC Registration No. 333-06125).

10.7 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 9⅜ percent Senior Notes due 2007 (Incorporated by reference to Exhibit 10.1 to our Form 10-Q for the quarter ended September 30, 1997).

10.8 Separation Agreement dated January 4, 2000 between Benton Oil and Gas Company and Mr. A.E. Benton. (Incorporated by reference to Exhibit 10.18 to our Form 10-K for the year ended December 31, 1999).

10.9 Consulting Agreement dated January 4, 2000 between Benton Oil and Gas Company and Mr. A.E. Benton. (Incorporated by reference to Exhibit 10.19 to our Form 10-K for the year ended December 31, 1999).

10.10 Employment Agreement dated July 10, 2000 between Benton Oil and Gas Company and Peter J. Hill. (Incorporated by reference to Exhibit 10.20 to our Form 8-K, filed June 6, 2000).

10.11 Benton Oil and Gas Company 1999 Employee Stock Option Plan (Incorporated by reference to Exhibit 10.21 to our Form 10-K, filed on April 2, 2001).

10.12 Benton Oil and Gas Company Non-Employee Director Stock Purchase Plan (Incorporated by reference to Exhibit 10.21 to our Form 10-K, filed on April 2, 2001).

10.13 Employment Agreement dated December 7, 2000 between Benton Oil and Gas Company and Steven W. Tholen (Incorporated by reference to Exhibit 10.21 to our Form 10-K, filed on April 2, 2001).

10.14 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).

10.15 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).

10.16 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).

10.17 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).

10.18 Michael B. Wray Termination Agreement effective May 7, 2001 (Incorporated by reference to Exhibit 10.28 to our Form 10-Q, filed on August 13, 2001).

10.19 Michael B. Wray Consulting Agreement effective May 7, 2001 (Incorporated by reference to Exhibit 10.29 to our Form 10-Q, filed on August 13, 2001).

10.20 Relocation/Reduction in Force Severance Plan effective June 5, 2001 (Incorporated by reference to Exhibit 10.30 to our Form 10-Q, filed on August 13, 2001).

10.21 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).

10.22 Amended Benton Oil and Gas Company Non-Employee Director Stock Purchase Plan (Incorporated by reference to Exhibit 10.1 to our Form 10-Q, filed on November 31, 2001)

10.23 Employment Agreement dated December 20, 2000 between Benton Oil and Gas Company and Robert Stephen Molina.

10.24 Employment Agreement dated November 14, 2001, between Benton Oil and Gas Company and Kurt A. Nelson.

10.25 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.

21.1 List of subsidiaries.

23.1 Consent of PricewaterhouseCoopers LLP.

23.2 Consent of Huddleston & Co., Inc.

23.3 Consent of Ryder Scott Company, L.P.

(b) *Reports on Form 8-K*

None.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors
and Stockholders of Benton Oil and Gas Company

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 Benton Oil and Gas Company and its subsidiaries at December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the related financial statement schedule listed in the index appearing under Item 14(a)(2) on page 46 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.

PRICEWATERHOUSECOOPERS LLP

Houston, Texas
March 28, 2002

BENTON OIL AND GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2001	December 31, 2000
	(In thousands, except per share data)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,024	$ 15,132
Restricted cash	12	12
Marketable securities	—	1,303
Accounts and notes receivable:		
Accrued oil sales	23,138	38,003
Joint interest and other, net	9,520	6,778
Prepaid expenses and other	1,839	2,404
Total Current Assets	43,533	63,632
Restricted Cash	16	10,920
Other Assets	4,718	5,891
Deferred Income Taxes	57,700	4,293
Investments In and Advances To Affiliated Companies	100,498	77,741
Property and Equipment:		
Oil and gas properties (full cost method-costs of $16,808 and $16,634 excluded from amortization in 2001 and 2000, respectively)	533,950	490,548
Furniture and fixtures	7,399	11,049
	541,349	501,597
Accumulated depletion, depreciation, and amortization	(399,663)	(377,627)
Total Property and Equipment	141,686	123,970
	$ 348,151	$ 286,447
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable, trade and other	$ 8,132	$ 12,804
Accrued expenses	25,840	25,797
Accrued interest payable	3,894	3,733
Income taxes payable	3,821	3,214
Short-term borrowings	—	5,714
Current portion of long-term debt	2,432	—
Total Current Liabilities	44,119	51,262
Long-Term Debt	221,583	213,000
Commitments and Contingencies	—	—
Minority Interest	14,826	9,281
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, 2001 and 2000; issued and outstanding 34,164 and 33,872 at December 31, 2001 and 2000	342	339
Additional paid-in capital	168,108	156,629
Accumulated deficit	(100,128)	(143,365)
Treasury stock, at cost, 50 shares	(699)	(699)
Total Stockholders' Equity	67,623	12,904
	$ 348,151	$ 286,447

See accompanying notes to consolidated financial statements.

BENTON OIL AND GAS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2001	2000	1999
	(In thousands, except per share data)		
Revenues			
Oil and natural gas sales	$122,386	$140,284	$ 89,060
Expenses			
Operating expenses	42,759	47,430	39,393
Depletion, depreciation and amortization	25,516	17,175	16,519
Write-down of oil and gas properties and impairments	468	1,346	25,891
General and administrative	20,072	16,739	25,969
Taxes other than on income	5,370	4,390	3,813
	94,185	87,080	111,585
Income (Loss) from Operations	28,201	53,204	(22,525)
Other Non-Operating Income (Expense)			
Investment earnings and other	3,088	8,559	8,986
Interest expense	(24,875)	(28,973)	(29,247)
Net gain on exchange rates	768	326	1,044
	(21,019)	(20,088)	(19,217)
Income (Loss) from Consolidated Companies Before Income Taxes and Minority Interests	7,182	33,116	(41,742)
Income Tax Expense (Benefit)	(35,698)	14,032	(7,526)
Income (Loss) Before Minority Interests	42,880	19,084	(34,216)
Minority Interests in Consolidated Subsidiary Companies	5,545	7,869	937
Income (Loss) from Consolidated Companies	37,335	11,215	(35,153)
Equity in Net Earnings of Affiliated Companies	5,902	5,313	2,869
Income (Loss) Before Extraordinary Income	43,237	16,528	(32,284)
Extraordinary Income on Debt Repurchase, Net of Tax of $0	—	3,960	—
Net Income (Loss)	$ 43,237	$ 20,488	$(32,284)
Net Income (Loss) Per Common Share:			
Basic:			
Income (Loss) before extraordinary income	$ 1.27	$ 0.54	$ (1.09)
Extraordinary Income	—	0.13	—
Net Income (Loss)	$ 1.27	$ 0.67	$ (1.09)
Diluted:			
Income (Loss) Before Extraordinary Income	$ 1.27	$ 0.53	$ (1.09)
Extraordinary Income	—	0.13	—
Net Income (Loss)	$ 1.27	$ 0.66	$ (1.09)

See accompanying notes to consolidated financial statements.

BENTON OIL AND GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	Common Shares Issued	Common Stock	Additional Paid-in Capital	Accumulated Deficit	Treasury Stock	Employee Note Receivable, Net	Total
				(In thousands)			
Balance at January 1, 1999	29,627	$296	$147,054	$(131,569)	$(699)	$(2,093)	$ 12,989
Issuance of common shares:							
Extension of warrants	—	—	24	—	—	—	24
Employee note receivable, net	—	—	—	—	—	2,093	2,093
Net Loss	—	—	—	(32,284)	—	—	(32,284)
Balance at December 31, 1999	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

See accompanying notes to consolidated financial statements.

BENTON OIL AND GAS COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2001	2000	1999
		(In thousands)	
Cash Flows From Operating Activities:			
Net income (loss)	$ 43,237	$ 20,488	$(32,284)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	25,516	17,175	16,519
Write-down and impairment of oil and gas properties	468	1,346	25,891
Amortization of financing costs	1,179	1,375	1,396
(Gain) loss on disposition of assets	(336)	60	44
Equity in earnings of affiliated companies	(5,902)	(5,313)	(2,869)
Allowance and write-off of employee notes and accounts receivable	365	331	6,231
Non-cash compensation related charges	474	—	—
Minority interest in undistributed earnings of subsidiaries	5,545	7,869	937
Extraordinary income from repurchase of debt	—	(3,960)	—
Tax benefits related to stock option compensation	11,008	—	—
Deferred income taxes	(53,407)	7,893	(9,210)
Changes in operating assets and liabilities:			
Accounts and notes receivable	11,756	(12,780)	(6,414)
Prepaid expenses and other	565	(769)	1,750
Accounts payable	(4,671)	9,487	(3,142)
Accrued interest payable	161	(953)	(711)
Accrued expenses	43	7,971	(166)
Income taxes payable	607	1,543	636
Net Cash Provided by (Used In) Operating Activities	36,608	51,763	(1,392)
Cash Flows from Investing Activities:			
Proceeds from sale of property and equipment	—	800	15,100
Additions of property and equipment	(43,364)	(57,196)	(36,984)
Investment in and advances to affiliated companies	(16,855)	(11,071)	(13,052)
Increase in restricted cash	(57)	(271)	(214)
Decrease in restricted cash	10,961	35,800	19,435
Purchases of marketable securities	(15,067)	(12,638)	(29,173)
Maturities of marketable securities	16,370	15,804	65,877
Net Cash Provided by (Used In) Investing Activities	(48,012)	(28,772)	20,989
Cash Flows from Financing Activities:			
Net proceeds from exercise of stock options and extension of warrants	—	330	24
Proceeds from issuance of short term borrowings and notes payable	21,112	15,087	—
Payments on short term borrowings and notes payable	(15,746)	(47,488)	(15,439)
(Increase) decrease in other assets	(70)	3,065	(233)
Net Cash Provided by (Used In) Financing Activities	5,296	(29,006)	(15,648)
Net Increase (Decrease) in Cash and Cash Equivalents	(6,108)	(6,015)	3,949
Cash and Cash Equivalents at Beginning of Year	15,132	21,147	17,198
Cash and Cash Equivalents at End of Year	$ 9,024	$ 15,132	$ 21,147
Supplemental Disclosures of Cash Flow Information:			
Cash paid during the year for interest expense	$ 25,721	$ 28,326	$ 30,346
Cash paid during the year for income taxes	$ 3,057	$ 2,950	$ 2,600

See accompanying notes to consolidated financial statements.

Supplemental Schedule of Noncash Investing and Financing Activities:

During the year ended December 31, 2000, we repurchased $12.0 million face value of our senior unsecured notes with the issuance of 4.2 million shares of common stock *(see Note 3)*.

During the year ended December 31, 1999, we recorded an allowance for doubtful accounts related to amounts owed to us by our former Chief Executive Officer, including the portion of the note secured by our stock and stock options of $2.1 million *(see Note 13)*.

See accompanying notes to consolidated financial statements.

Note 1 — Organization and Summary of Significant Accounting Policies

Organization

We engage in the exploration, development, production and management of oil and gas properties. We conduct our business principally in Venezuela and 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 Geoilbent, Ltd. ("Geoilbent") and Arctic Gas Company ("Arctic Gas"), based on a fiscal year ending September 30 *(see Note 2)*.

Revenue Recognition

Oil revenue is accrued monthly based on production and delivery. Each quarter, Benton-Vinccler invoices Petroleos de Venezuela, S.A. ("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. It also provides 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 amortized cost. The marketable securities that we may purchase are limited to those defined as Cash Equivalents in the indentures for our senior unsecured notes. 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 $1.3 million at December 31, 2000.

Accounts and Notes Receivable

Allowance for doubtful accounts related to employee notes at December 31, 2001 and 2000 was $6.5 million and $6.2 million, respectively *(see Note 13)*. Allowance for doubtful accounts related to joint interest and other accounts receivable was $0.3 million at December 31, 2000.

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, $1.5 million and $2.1 million for the years ended December 31, 2001, 2000 and 1999, respectively, and capitalized interest of $0.9 million and $0.6 million for the years ended December 31, 2001 and 2000, respectively. 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 2001, 2000 and 1999, the Company recognized $0.5 million, $1.3 million and $25.9 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, 2001 consisted of the following by year incurred (in thousands):

	Total	2001	2000	1999	Prior to 1999
Property acquisition costs	$15,106	$ —	$ —	$—	$15,106
Exploration costs	1,702	174	518	46	964
	$16,808	$174	$518	$46	$16,070

Substantially all of the excluded costs at December 31, 2001 relate to the acquisition of Benton Offshore China Company and exploration related to its Wan "An Bei property. The remaining excluded costs of $0.6 million are expected to be included in amortizable costs during the next two to three years. 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, 2001, 2000 and 1999 was $22.1 million, $15.3 million and $14.8 million ($2.26, $1.68 and $1.53 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 $3.4 million, $1.8 million and $1.6 million for the years ended December 31, 2001, 2000 and 1999, respectively.

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

	2001	2000
Proved property costs	$ 501,923	$ 458,571
Costs excluded from amortization	16,808	16,634
Oilfield inventories	15,219	15,343
Furniture and fixtures	7,399	11,049
	541,349	501,597
Accumulated depletion, impairment and depreciation	(399,663)	(377,627)
	$ 141,686	$ 123,970

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 likelihood of utilization of net operating losses in 2002. *See Note 16 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K.*

Foreign Currency

We have significant operations outside of the United States, principally in Venezuela and Russia. These countries 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.

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 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 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, 2001 and 2000, was approximately $138.1 million and $137.0 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, 2001 and, in accordance with SFAS 130, have not provided a separate statement of comprehensive income.

Derivatives and Hedging

Statement of Financial Accounting Standards No. 133 ("SFAS 133"), as amended, establishes accounting and reporting standards for derivative instruments and hedging activities. The Company has not used derivative or hedging instruments since 1996.

Minority Interests

We record a minority interest attributable to the minority shareholders of our Venezuela subsidiaries. The minority interests in net income and losses are generally subtracted or added to arrive at consolidated net income. However, as of December 31, 1998, losses attributable to the minority shareholder of Benton-Vinccler, our 80 percent owned subsidiary, exceeded its interest in equity capital creating an equity deficit of $3.5 million. Accordingly, $3.5 million of income attributable to the minority shareholder of Benton-Vinccler in 1999 was included in our consolidated net loss, eliminating the minority shareholder's equity deficit.

New Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued Statements of Financial Accounting Standards No. 141 "Business Combinations" ("SFAS 141") and No. 142 "Goodwill and Other Intangible Assets" ("SFAS 142"). SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for under the purchase method. For all business combinations for which the date of acquisition is after June 30, 2001, SFAS 141 also establishes specific criteria for the recognition of intangible assets separately from goodwill. SFAS 141 also requires unallocated negative goodwill (in a case where the purchase price is less than fair market value of the acquired assets) to be written off immediately as an extraordinary gain, rather than deferred and amortized. SFAS 142 changes the accounting for goodwill and other intangible assets after an acquisition. The most significant changes made by SFAS 142 are: 1) goodwill and intangible assets with indefinite lives will no longer be amortized; 2) goodwill and intangible assets with indefinite lives must be tested for impairment at least annually; and 3) the amortization period for intangible assets with finite lives will no longer be limited to 40 years. In August 2001, the FASB also approved SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS 144"). SFAS 144 replaces SFAS 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of." The new accounting model for long-lived assets to be disposed of by sale applies to all long-lived assets, including discontinued operations, and replaces the provisions of APB Opinion No. 30, "Reporting Results of Operations-Reporting the Effects of Disposal of a Segment of a Business", for the disposal of segments of a business. SFAS 144 requires that those long-lived assets be measured at the lower of carrying amount or fair value less cost to sell, whether reported in continuing operations or in discontinued operations. Therefore, discontinued operations will no longer be measured at net realizable value or include amounts for operating losses that have not yet occurred. SFAS 144 also broadens the reporting of discontinued operations to include all components of an entity with operations that can be distinguished from the rest of the entity and that will be eliminated from the ongoing operations of the entity in a disposal transaction. The provisions of SFAS 144 are effective for financial statements issued for fiscal years beginning after December 15, 2001 and, generally are to be applied prospectively. These statements are not expected to have a material impact on our financial position, results of operations, or cash flows.

In June 2001, the FASB also approved for issuance SFAS 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets such as wells and production facilities. SFAS 143 guidance covers (1) the timing of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that an asset retirement cost should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company will adopt the statement effective no later than January 1, 2003, as required. The transition adjustment resulting from the adoption of SFAS 143 will be reported as a cumulative effect of a change in accounting principle. At this time, the Company cannot reasonably estimate the effect of the adoption of this statement on its financial position, results of operations or cash flows.

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 1999 and 2000 have been reclassified to conform to the 2001 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.

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	
	2001	2000	2001	2000	2001	2000
Investments:						
In equity in net assets	$28,056	$28,056	$(1,814)	$(2,218)	$ 26,242	$25,838
Other costs, net of amortization	(99)	(202)	28,579	19,058	28,480	18,856
Total investments	27,957	27,854	26,765	16,840	54,722	44,694
Advances	—	—	28,829	21,986	28,829	21,986
Equity in earnings (losses)	19,307	12,310	(2,360)	(1,249)	16,947	11,061
Total	$47,264	$40,164	$53,234	$37,577	$100,498	$77,741

Note 3 — Long-Term Debt and Liquidity

Long-Term Debt

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

	December 31, 2001	December 31, 2000
Senior unsecured notes with interest at 9.375% See description below	$105,000	$105,000
Senior unsecured notes with interest at 11.625% See description below	108,000	108,000
Note payable with interest at 8.7% See description below	5,100	—
Note payable with interest at 39% See description below	5,235	—
Non-interest bearing liability with a face value of $744 discounted at 7%. See description below	680	—
	224,015	213,000
Less current portion	2,432	—
	$221,583	$213,000

In November 1997, we issued $115 million in 9.375 percent senior unsecured notes due November 1, 2007 ("2007 Notes"), of which we subsequently repurchased $10 million at their par value. In May 1996, we issued $125 million in 11.625 percent senior unsecured notes due May 1, 2003 ("2003 Notes"), of which we repurchased $17 million at their discounted value in September 2000 and November 2000 with the issuance of 4.2 million common shares with a market value of $9.3 million and cash of $3.5 million plus accrued interest. Interest on the notes is due May 1 and November 1 of each year. The indenture agreements provide for certain limitations on liens, additional indebtedness, certain investments and capital expenditures, dividends, mergers and sales of assets. In August 2001, we received the requisite consents from the holders of the 2003 Notes and 2007 Notes to amend the indentures governing the notes, and the supplemental indentures have become operative. The amendments enable Arctic Gas Company to incur non-recourse debt of up to $77 million to fund its oil and gas development program and remove stock restrictions. For all of 2001, and at December 31, 2001, we were in compliance with all covenants of the indentures.

In March 2001, Benton-Vinccler borrowed $12.3 million from a Venezuelan commercial bank, in the form of two loans, for construction of a 31-mile oil pipeline that will connect the Tucupita Field production facility with the Uracoa central processing unit. The first loan, with an original principal amount of $6 million, bears interest payable monthly based on 90-day LIBOR (3.7 Percent at December 31, 2001) plus 5 percent with principal payable quarterly for five years. The second loan, in the amount of 4.4 billion Venezuelan 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 2001 was 39 percent with an effective interest rate of 31 percent taking into account exchange rate gains resulting from devaluation of the Bolivar during the quarter. In February 2002, the Bolivar was allowed to float against the U.S. dollar. Principal on the second loan is payable quarterly for five years beginning in September 2001. The loans provide for certain limitations on dividends, mergers and sale of assets. At December 31, 2001, we were in compliance with all covenants of the loans.

In 2001, a dispute arose over collection by municipal taxing regimes on 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 principal payment requirements for our long-term debt outstanding at December 31, 2001 are as follows (in thousands):

2002	$ 2,432
2003	111,112
2004	2,432
2005	2,432
2006	607
Subsequent Years	105,000
	$224,015

Liquidity

We have significant debt principal obligations payable in 2003 and 2007. During September 2000, we exchanged 2.7 million shares of our common stock, plus accrued interest, for $8 million face value of our 11.625 percent senior notes due in 2003 and purchased $5 million face value of our 2003 senior notes for cash of $3.5 million plus accrued interest. Additionally, in November 2000, we exchanged 1.5 million shares of our common stock, plus accrued interest, for an aggregate $4 million face value of our 11.625 percent senior notes due in 2003.

While we can give you no assurance, we currently believe that our cash flow from operations, if supplemented by borrowings if required, 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 price levels, production and the availability of short-term working capital facilities of up to $12 million currently during the time periods between the submission of quarterly invoices to PDVSA by Benton-Vinccler and the subsequent payments of these invoices by PDVSA and other financial alternatives. Actual results could be materially affected if there is a significant decrease in either price or production levels related to the South Monagas Unit. 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 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 significant debt obligations payable in May 2003 and November 2007 of $108 million and $105 million, respectively. Our ability to meet our debt obligations and to reduce our level of debt depends on the successful implementation of our strategic objectives, in particular the timely sale of our interest in Arctic Gas. While we believe the Proposed Arctic Gas Sale will be consummated, there can be no assurance that the transaction will close.

In the event that the Transaction does not close, we will be required to review additional strategic alternatives to repay the $108 million due in May 2003 in debt, including but not limited to, selling all or part of our existing assets in Venezuela and Russia, restructuring our debt, some combination thereof, or selling the Company. However, no assurances can be given that any of these steps can be successfully completed or that we ultimately will determine that any of the steps should be taken.

We, with the advice of our financial and legal advisers and after having conducted a comprehensive review to consider our strategic alternatives, initiated a process in May 2001 intended to effectively extend the maturity of the senior notes due May 1, 2003 by exchanging new 13.125 percent senior notes due December 2007 plus warrants to purchase shares of our common stock for each of the 2003 Notes. While we believe the terms of the exchange offer made to the holders of the 2003 Notes were in the best interest of the noteholders and our shareholders, the majority of the noteholders would not exchange their notes for notes of a longer maturity on economic terms which were acceptable to us. As a result, the exchange offer was withdrawn in July 2001. In August 2001, we solicited and received the requisite consents from the holders of both the 2003 Notes and the 2007 Notes to amend certain covenants in the indentures governing the notes to enable Arctic Gas to incur nonrecourse debt of up to $77 million to fund its oil and gas development program and remove stock restrictions. As an incentive to consent, we offered to pay each noteholder an amount in cash equal to $2.50 per $1,000 principal amount of notes held for which executed consents were received. The total amount of consent fees paid to the consenting noteholders was $0.3 million, which has been included in general and administrative expenses.

Additionally, we implemented a plan designed to lower operating costs, reduce general and administrative costs at our corporate headquarters and to transfer geological and geophysical activities to our overseas offices in Maturin, Venezuela and in Western Siberia and Moscow, Russia.

On February 27, 2002, we signed a Sale and Purchase Agreement to sell our 68 percent interest in Arctic Gas Company to a nominee of the Yukos Oil Company for $190 million plus approximately $30 million as repayment of intercompany loans owed to us by Arctic Gas. If this transaction closes, it will alleviate our short-term liquidity issue. However, in the event the transaction does not close, we will be required to review additional strategic alternatives to repay the $108 million of 11⅝ percent senior notes due May 2003.

Note 4 — Commitments and Contingencies

On February 17, 1998, the WRT Creditors Liquidation Trust ("WRT Trust") filed suit in the United States Bankruptcy Court, Western District of Louisiana against us and Benton Oil and Gas Company of Louisiana, a.k.a. Ventures Oil & Gas of Louisiana ("BOGLA"), seeking a determination that the sale by BOGLA to Tesla Resources Corporation ("Tesla"), a wholly owned subsidiary of WRT Energy Corporation, of certain West Cote Blanche Bay properties for $15.1 million, constituted a fraudulent conveyance under 11 U.S.C. Sections 544, 548 and 550 (the "Bankruptcy Code"). The alleged basis of the claim is that Tesla was insolvent at the time of its acquisition of the properties, and that it paid a price in excess of the fair value of the property. A trial commenced on May 1, 2000 that concluded at the end of August 2000, and post trial briefs were filed. The WRT Trust has filed a Notice of Appeal with the Bankruptcy Court; however, we believe that the appeal will result in an outcome consistent with the court's prior decision.

In May 1996, we entered into an agreement with Morgan Guaranty that provided for an $18 million cash collateralized five-year letter of credit to secure our performance of the minimum exploration work program required on the Delta Centro Block in Venezuela. As a result of expenditures made related to the exploration work program, the letter of credit had been reduced to $7.7 million as of December 31, 2000. In January 2001, we and our bidding partners reached an agreement to terminate the remainder of the exploration work program in exchange for the unused portion of the standby letter of credit of $7.7 million.

We have employment contracts with four executive officers which provide for annual base salaries, bonus compensation and various benefits. The contracts provide for the continuation of salary and benefits for the respective terms of the agreements in the event of termination of employment without cause. These agreements expire at various times from November 11, 2002 to July 9, 2003.

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.

In October 2001, we received a letter from the New York Stock Exchange ("NYSE") notifying us that we have fallen below the continued listing standards 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 as of September 30, 2001, was $16.0 million. In accordance with the NYSE's rules, we submitted a plan to the NYSE in December detailing how we expect 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. These initiatives include continued cost reductions, production enhancements, selling all or part of our assets in Venezuela and/or Russia, restructuring the debt or some combination of these alternatives. Failure to achieve the financial and operational goals may result in being subject to NYSE trading suspension at the point the initiative or goal is not met. As a result of a delisting, an investor will find it more difficult to dispose or obtain quotations or market value of our common stock, which may adversely affect the marketability of our common stock. However, given our strategic plan referenced above, we are optimistic that we will be able to meet the NYSE requirements in the future and, consequently, do not expect our stock to be delisted.

Geoilbent has reduced its 2002 capital budget to approximately $16.6 million, of which $2.7 million is for the North Gubkinskoye Field, $9.7 million is for the South Tarakovskoye Field, $2.2 million is to carry out seismic and related exploration activity and $2.0 million is for natural gas plant economic, technical and feasibility studies. Geoilbent's 2002 operating budget includes $16 million for principal payments on the loan facility. In addition, Geoilbent had outstanding accounts payable of $26.6 million as of December 31, 2001, primarily to contractors and vendors for drilling and construction services.

Although Geoilbent's reduced capital expenditure budget may help to alleviate any shortfall of funds available to make payments to the banks and its creditors as those payments come due, it is uncertain that Geoilbent's cash flow from operations will be sufficient to do so, and it may be necessary for Geoilbent to obtain capital contributions from its partners, including the Company, to have sufficient funds to make these payments on a timely basis. Although the Company may consider making such a capital contribution, there can be no assurances that the Company will do so, nor can there be any assurances that Geoilbent's other partner will be willing or able to do so. Under Russian law, a creditor can force a company into involuntary bankruptcy if the company's payments have been due for more than 90 days.

In the normal course of our business, we may periodically become subject to actions threatened or brought by our investors or partners in connection with the operation or development of our properties or the sale of securities. We are also subject to ordinary litigation that is incidental to our business, none of which is expected to have a material adverse effect on our financial position, results of operations or liquidity.

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):

	2001	2000	1999
Venezuelan municipal taxes	$4,447	$3,164	$2,303
Severance and production taxes	—	28	—
Franchise taxes	121	131	139
Payroll and other taxes	802	1,067	1,371
	$5,370	$4,390	$3,813

Taxes on Income

The tax effects of significant items comprising our net deferred income taxes as of December 31, 2001 and 2000 are as follows (in thousands):

	2001	2000
Deferred tax assets:		
Operating loss carryforwards	$ 49,000	$ 37,142
Difference in basis of property	19,300	4,948
Other	9,100	16,410
Valuation allowance	(19,700)	(54,207)
Net deferred tax asset	$ 57,700	$ 4,293

The valuation allowance decreased by $37.0 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 and in particular the Proposed Arctic Gas Sale. *See Note 16 to the Audited Financial Statements in Item 14 — Exhibits, Financial Statement Schedules and Reports on Form 8-K.*

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

	2001	2000	1999
Income (loss) before income taxes United States	$(26,572)	$(13,034)	$(38,637)
Foreign	33,754	46,150	(3,105)
Total	$ 7,182	$ 33,116	$(41,742)

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

	2001	2000	1999
Current:			
United States	$ 1	$ 215	$(2,216)
Foreign	6,700	5,925	3,900
	$ 6,701	$ 6,140	$ 1,684
Deferred:			
United States	$(42,405)	$ —	$ —
Foreign	6	7,892	(9,210)
	(42,399)	7,892	(9,210)
	$(35,698)	$14,032	$(7,526)

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

	2001	2000	1999
Computed tax expense at the statutory rate	$ 4,580	$13,451	$(13,606)
State income taxes, net of federal effect	—	(343)	(307)
Effect of foreign source income and rate differentials on foreign income	1,675	(1,826)	4,507
Change in valuation allowance	(53,413)	2,294	5,951
Prior year adjustments	2,304	1,637	(847)
Effect of tax law changes	—	—	(2,220)
Reclass paid-in capital	11,007	—	—
All other	215	679	—
Sub-total income tax expense (benefit)	(33,632)	15,892	(6,522)
Effects of recording equity income of certain affiliated Companies on an after-tax basis	(2,066)	(1,860)	(1,004)
Total income tax expense (benefit)	$(35,698)	$14,032	$ (7,526)

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. The effect of tax law changes relates to benefits from the Venezuela-United States tax treaty ratified in 1999.

At December 31, 2001, we had, for federal income tax purposes, operating loss carryforwards of approximately $136 million, expiring in the years 2003 through 2021.

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

During 1989, we adopted our 1989 Nonstatutory Stock Option Plan covering 2,000,000 shares of common stock which were granted to key employees, directors, independent contractors and consultants at prices equal to or below market prices, exercisable over various periods. The plan was amended during 1990 to add 1,960,000 shares of common stock.

In September 1991, we adopted the 1991-1992 Stock Option Plan and the Directors' Stock Option Plan. The 1991-1992 Stock Option Plan, as amended in 1996 and 1997, permitted the granting of stock options to purchase up to 4,800,000 shares of the Company's common stock in the form of ISOs and NQSOs to our officers and employees of the Company. Options were granted 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 1991-1992 Stock Option Plan. All options granted to date under the plan vest ratably over a three-year period from their dates of grant and expire ten years from grant date or one year after retirement, if earlier. Subsequent to shareholder approval of the 1998 Stock-Based Incentive Plan discussed below, our Board of Directors discontinued future grants under the 1991-1992 Stock Option Plan.

In June 1998, our shareholders approved the adoption of the 1998 Stock-Based Incentive Plan. The 1998 Stock-Based Incentive Plan authorized up to 1,400,000 shares of our common stock for grants of ISOs and

NQSOs, stock appreciation rights, restricted stock awards and bonus stock awards to our employees or employees of our subsidiaries or associated companies, subject to the dollar limitations imposed by the Internal Revenue Code. The exercise price of stock options granted under the plan were no less than the fair market value of our common stock on the date of grant. 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 under the 1998 Stock-Based Incentive Plan vest ratably over a three-year period from their dates of grant and expire ten years from grant date or one year after retirement, if earlier.

In November 1999, we adopted the 1999 Stock Option Plan. 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 and NQSOs to directors, employees and consultants. Options may be granted as 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.

In July 2001, we adopted 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 ISOs and NQSOs 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.

The Directors' Stock Option Plan permitted the granting of nonqualified stock options ("Director NQSOs") to purchase up to 400,000 shares of common stock to our nonemployee directors. Upon election as a director and annually thereafter, each individual who served as a nonemployee director was automatically granted an option to purchase 10,000 shares of common stock at a price not less than the fair market value of common stock on the date of grant. All Director NQSOs vested automatically on the date of the grant of the options, and at December 31, 2001, options to purchase 280,000 shares of common stock were both outstanding and exercisable. The Director stock option plan has been replaced with the Non-Employee Director Stock Purchase Plan. No additional Director NQSO's will be granted under the Directors Stock Option Plan.

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. Each non-employee director may elect once each year, prior to January 1, to be effective for the following year and until a new election is made, 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 will be 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 will have a restriction upon their sale for one year from the date of issuance. As of December 31, 2001, 292,170 shares had been issued from the plan.

A summary of the status of our stock option plans as of December 31, 2001, 2000 and 1999 and changes during the years ending on those dates is presented below (shares in thousands):

	2001		2000		1999	
	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares
Outstanding at beginning of the year:	$7.74	5,660	$7.55	6,300	$11.27	3,712
Options granted	1.65	1,684	2.06	240	2.37	2,701
Options exercised	—	—	2.53	(85)	—	—
Options cancelled	6.43	(479)	4.90	(795)	6.10	(113)
Outstanding at end of the year	6.36	6,865	7.74	5,660	7.55	6,300
Exercisable at end of the year	8.32	4,800	9.68	4,099	11.23	3,251

Significant option groups outstanding at December 31, 2001 and related weighted average price and life information follow:

Range of Exercise Prices	Number Outstanding At December 31, 2001	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at December 31, 2001	Weighted-Average Exercise Price
$ 1.55-$ 2.75	3,974,332	8.42	$2.05	1,908,664	$2.32
$ 4.89-$ 7.00	409,333	2.77	6.19	409,333	6.19
$ 7.25-$11.00	903,033	3.17	8.62	903,033	8.62
$11.50-$16.50	1,080,665	4.91	13.59	1,080,665	13.59
$17.38-$24.13	497,833	5.05	21.13	497,833	21.13
	6,865,196			4,799,528	

The weighted average fair value of the stock options granted from our stock option plans during 2001, 2000, and 1999 was $1.33, $1.65 and $1.88, 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:

	2001	2000	1999
Expected life	10.0 years	9.1 years	9.3 years
Risk-free interest rate	5.1%	6.1%	5.9%
Volatility	72%	74%	73%
Dividend Yield	0%	0%	0%

We account 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 2001, 2000 and 1999 would have been as follows (in thousands, except per share data):

	2001	2000	1999
Net income (loss)	$40,813	$16,224	$(38,441)
Net income (loss) per common share:			
Basic	$ 1.20	$ 0.53	$ (1.30)
Diluted	$ 1.20	$ 0.53	$ (1.30)

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, 2001, 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 $10.88 to $11.88 which vest over three to four years. At December 31, 2001, a total of 208,500 options issued outside of the plans were both outstanding and exercisable. On January 22, 2002, 19,000 of these options expired. Our expenses associated with these options were not material.

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, 2001 were (shares in thousands):

Date Issued	Expiration Date	Exercise Price	Issued	Outstanding
July 1994	July 2004	$ 7.50	150	8
September 1994	September 2002	9.00	250	250
December 1994	December 2004	12.00	50	50
June 1995	June 2007	17.09	125	125
January 1996	January 2002	11.00	588	577
			1,163	1,010

Note 8 — Operating Segments

We regularly allocate resources to and assesses 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. Revenues from the Venezuela and Russia operating segments are 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.

	Venezuela	USA and Other	Russia (In thousands)	Eliminations	Consolidated
Year ended December 31, 2001:					
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

	Venezuela	USA and Other	Russia	Eliminations	Consolidated
			(In thousands)		
Year ended December 31, 2000:					
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

	Venezuela	USA and Other	Russia (In thousands)	Eliminations	Consolidated
Year ended December 31, 1999:					
Revenues					
Oil and natural gas sales	$ 89,060	$ —	$ —	$ —	$ 89,060
	89,060	—	—	—	89,060
Expenses					
Operating expenses	38,683	34	676	—	39,393
Depletion, depreciation and amortization	15,705	801	13	—	16,519
General and administrative	4,482	19,729	1,758	—	25,969
Taxes other than on income	2,501	1,326	(14)	—	3,813
Total expenses	61,371	21,890	2,433	—	85,694
Income (loss) from operations	27,689	(21,890)	(2,433)	—	3,366
Other non-operating income (expense)					
Investment earnings and other	758	9,510	2	(1,284)	8,986
Interest expense	(6,834)	(23,697)	—	1,284	(29,247)
Net gain on exchange rates	1,033	11	—	—	1,044
Intersegment revenues (expenses)	(8,906)	8,906	—	—	—
Equity in income of affiliated companies	—	—	2,869	—	2,869
	(13,949)	(5,270)	2,871	—	(16,348)
Income (loss) before income taxes	13,740	(27,160)	438	—	(12,982)
Income tax expense (benefit)	(7,554)	(170)	198	—	(7,526)
Operating segment income (loss)	21,294	(26,990)	240	—	(5,456)
Write-down of oil and gas properties and impairments	—	(25,891)	—	—	(25,891)
Minority interest	(937)	—	—	—	(937)
Net income (loss)	$ 20,357	$(52,881)	$ 240	$ —	$(32,284)
Total assets	$124,942	$188,000	$ 61,989	$ (98,620)	$276,311
Additions to properties	$ 25,367	$ 11,579	$ 38	$ —	$ 36,984

Note 9 — Russian Operations

Geoilbent, Ltd.

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 December 31, 2001, 2000 and 1999 were 5,184,745 Bbls, 4,247,590 Bbls and 4,267,647 Bbls, respectively. Prices for crude oil for the years ended December 31, 2001, 2000 and 1999 averaged $19.51, $18.54 and $8.53 per barrel, respectively. Depletion expense attributable to Geoilbent for the years ended December 31, 2001, 2000 and 1999 was $2.13, $2.29 and $2.27 per barrel, respectively.

Summarized financial information for Geoilbent follows (in thousands). All amounts represent 100 percent of Geoilbent.

	2001	2000	1999
Year ended September 30:			
Revenues			
Oil sales	$101,159	$ 78,735	$ 36,424
Expenses			
Selling and distribution expenses	9,875	4,612	3,654
Operating expenses	11,256	9,798	4,364
Depletion, depreciation and amortization	14,918	9,557	9,669
General and administrative	5,650	3,407	2,655
Taxes other than on income	26,011	18,286	8,208
	67,710	45,660	28,550
Income from operations	33,449	33,075	7,874
Other non-operating income (expense)			
Investment earnings and other	649	53	1,375
Interest expense	(7,548)	(8,145)	(3,572)
Net gain (loss) on exchange rates	781	(596)	5,152
	(6,118)	(8,688)	2,955
Income before income taxes	27,331	24,387	10,829
Income tax expense	6,754	6,321	1,333
Net income	$ 20,577	$ 18,066	$ 9,496
At September 30:			
Current assets	$ 34,696	$ 30,070	$ 25,699
Other assets	187,593	163,219	139,488
Current liabilities	60,439	32,700	10,276
Other liabilities	22,550	41,866	54,254
Net equity	139,300	118,723	100,657

The European Bank for Reconstruction and Development ("EBRD") and International Moscow Bank ("IMB") together have agreed to lend up to $65 million to Geoilbent, based on achieving certain reserve and production milestones, under parallel reserve-based loan agreements. Under these loan agreements, we and other shareholders of Geoilbent have significant management and business support obligations. Each shareholder is jointly and severally liable to EBRD and IMB for any losses, damages, liabilities, costs, expenses and other amounts suffered or sustained arising out of any breach by any shareholder of its support obligations. The loans bear an average interest rate of 15 percent payable on January 27 and July 27 each year. Principal payments will be due in varying installments on the semiannual interest payment dates beginning January 27, 2001 and ending by July 27, 2004. The loan agreements require that Geoilbent meet certain financial ratios and covenants, including a minimum current ratio, and provides for certain limitations on liens, additional indebtedness, certain investment and capital expenditures, dividends, mergers and sales of assets. As of September 30, 2001, Geoilbent was not in compliance with the current ratio covenant, but received a waiver from EBRD. Geoilbent began borrowing under these facilities in October 1997 and had borrowed a total of $48.5 million and repaid $10.0 million through September 30, 2001. The proceeds from the loans were used by Geoilbent to develop the North Gubkinskoye Field in West Siberia, Russia. The principal payment requirements for the long-term debt of Geoilbent at September 30, 2001 are as follows for the years ending September 30 (in thousands):

2002	$16,000
2003	11,000
2004	11,550
	$38,550

During 1996 and 1997, we incurred $4.1 million in financing costs related to the establishment of the EBRD financing which are recorded in other assets and are subject to amortization over the life of the facility. Geoilbent reimbursed $2.6 million of such costs in 2000.

In October 1995, Geoilbent entered into an agreement with Morgan Guaranty for a credit facility under which we provide cash collateral for the loans to Geoilbent. In conjunction with Geoilbent's reserve-based loan agreements with the EBRD and IMB, repayment of the credit facility was subordinated to payments due to the EBRD and IMB and, accordingly, the credit facility was reclassified from current to long-term in 1998. In May 2001, Geoilbent entered into an agreement with IMB to borrow $3.3 million to repay the Morgan credit facility and, as a result, our cash collateral was returned. The loan from IMB is due on November 15, 2002, bears interest at LIBOR plus 6 percent and requires quarterly payments of principal and interest of approximately $0.6 million beginning in August 2001.

Excise, pipeline and other tariffs and taxes continue to be levied on all oil producers and certain exporters, including an oil export tariff that decreased to $8.00 per ton (approximately $1.10 per barrel) from 23.4 Euros per ton (approximately $2.85 per barrel). We are unable to predict the impact of taxes, duties and other burdens for the future for our Russian operations.

Geoilbent has reduced its 2002 capital budget to approximately $16.6 million, of which $2.7 million is for the North Gubkinskoye Field, $9.7 million is for the South Tarakovskoye Field, $2.2 million is to carry out seismic and related exploration activity and $2.0 million is for natural gas plant economic, technical and feasibility studies. Geoilbent's 2002 operating budget includes $16 million for principal payments on the loan facility. In addition, Geoilbent had outstanding accounts payable of $26.6 million as of December 31, 2001, primarily to contractors and vendors for drilling and construction services.

Although Geoilbent's reduced capital expenditure budget may help to alleviate any shortfall of funds available to make payments to the banks and its creditors as those payments come due, it is uncertain that Geoilbent's cash flow from operations will be sufficient to do so, and it may be necessary for Geoilbent to obtain capital contributions from its partners, including the Company, to have sufficient funds to make these payments on a timely basis. Although the Company may consider making such a capital contribution, there can be no assurances that the Company will do so, nor can there be any assurances that Geoilbent's other partner will be willing or able to do so. Under Russian law, a creditor can force a company into involuntary bankruptcy if the company's payments have been due for more than 90 days.

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. Pursuant to the Cooperation Agreement, we have received voting shares representing a 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. As of December 31, 2001, we had loaned $28.5 million to Arctic Gas pursuant to an interim credit facility, with interest at LIBOR plus 3 percent, and had earned the right to remove restrictions from shares representing an approximate 11 percent equity interest. From December 1998 through September 2001, we purchased shares representing an additional 28 percent equity interest not subject to any sale or transfer restrictions. We owned a total of 68 percent of the outstanding voting shares of Arctic Gas as of December 31, 2001, of which approximately 39 percent were not subject to any restrictions and represent our equity interest.

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, 2001, 2000 and 1999 was 39 percent, 29 percent and 24 percent, respectively. We recorded as our share in the losses of Arctic Gas $1.1 million, $0.7 million and $0.4 million for the years ended September 30, 2001, 2000 and 1999, 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.

	2001	2000	1999
Year ended September 30:			
Revenues			
Oil Sales	$13,374	$ 3,354	$ —
Expenses			
Selling and distribution expenses	3,867	—	—
Operating expense	3,483	1,004	—
Depletion, depreciation and amortization	1,032	432	85
General and administrative	3,025	2,154	2,941
Taxes other than on income	3,881	1,422	64
	15,288	5,012	3,090
Loss from operations	(1,914)	(1,658)	(3,090)
Other non-operating income (expense)			
Other income (expense)	54	(14)	585
Interest and foreign exchange expense	(1,848)	(1,558)	(868)
	(1,794)	(1,572)	(283)
Loss before income taxes	(3,708)	(3,230)	(3,373)
Income tax expense	—	188	—
Net loss	$(3,708)	$(3,418)	$(3,373)

	2001	2000	1999
At September 30:			
Current assets	$ 4,423	$ 1,205	$ 1,513
Other assets	14,986	10,120	5,043
Current liabilities	35,658	23,955	18,068
Net (deficit)	(16,249)	(12,630)	(11,512)

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 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.

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

In December 1999, we entered into agreements with Schlumberger and Helmerich & Payne to further develop the South Monagas Unit pursuant to a long-term incentive-based development program. Schlumberger has agreed to financial incentives intended to reduce drilling costs, improve initial production rates of new wells and to increase the average life of the downhole pumps at South Monagas Unit. As part of Schlumberger's commitment to the program, it provides additional technical and engineering resources on-site full-time in Venezuela. As of December 31, 2000, 26 new oil wells and 2 re-entry oil wells have been drilled under the alliance program.

In January 2001, we suspended the development drilling program until the second half of 2001 in order to thoroughly review all aspects of operations in order to integrate field performance to date with revised computer simulation modeling and improved well completion technology. In August 2001, drilling recommenced in the Uracoa Field under the alliance agreement with Schlumberger. As of December 31, 2001, we drilled 8 new wells in Uracoa and we identified 7 well locations in undepleted portions of the Tucupita Field, each of the first two wells is producing at a sustainable rate of 2,000 Bbls of oil per day as of March 15, 2002. In August 2001, Benton-Vinccler signed an agreement to amend the alliance with Schlumberger. The amended long-term incentive-based alliance continues to provide incentives intended to improve initial production rates of new wells and to increase the average life of the downhole pumps at South Monagas Unit. In addition, Schlumberger has agreed to provide drilling and completion services for new wells utilizing fixed lump-sum pricing. We chose not to renew the alliance with Helmerich & Payne and have entered into a standard drilling contract with Flint South America, Inc. In September 2001, we completed the majority of the reservoir simulation study of the Uracoa Field and expect to complete a revised field development plan, incorporating the results of this study in 2002.

In January 1996, we and our bidding partners, predecessor companies acquired over time by Burlington Resources, Inc. ("Burlington") and Anadarko Petroleum Corporation ("Anadarko"), were awarded the right to explore and develop the Delta Centro Block in Venezuela. The contract required a minimum exploration work program consisting of a seismic survey and the drilling of three wells within five years. At the time the block was tendered for international bidding, PDVSA estimated that this minimum exploration work program would cost $60 million and required that we and the other partners each post a performance surety bond or standby letter of credit for our pro rata share of the estimated work commitment expenditures. We had a 30 percent interest in the exploration venture, with Burlington and Anadarko each owning a 35 percent interest. In July 1996, formal agreements were finalized and executed, and we posted an $18 million standby letter of credit, collateralized in full by a time deposit, to secure our 30 percent share of the minimum exploration work program. During 1999, the Block's first exploration well, the Jarina 1-X, penetrated a thick potential reservoir sequence, but encountered no hydrocarbons. In January 2001, we and our bidding partners reached an agreement with Corporacion Venezolana del Petroleo, S.A. to terminate the contract in exchange for the unused portion of the standby letter of credit of $7.7 million. As a result, we included $7.7 million of restricted cash that collateralized the letter of credit in the Venezuelan full cost pool. As of December 31, 2001, our share of expenditures to date on the Delta Centro Block was $23.1 million.

Note 11 — United States Operations

In April and May 2000, we entered into agreements with Coastline Energy Corporation ("Coastline") for the purpose of acquiring, exploring and developing oil and natural gas prospects both onshore and in the state waters of the Gulf Coast states of Texas, Louisiana and Mississippi. Under the agreements, Coastline will evaluate prospects in the Gulf Coast area for possible acquisition and development by us. During the 18-month term of the exploration agreement, we will reimburse Coastline for certain of its overhead and prospect evaluation costs. Under the agreements, for prospects evaluated by Coastline and that we acquire, Coastline will receive compensation based on (a) oil and natural gas production acquired or developed and (b) the profits, if any, resulting from the sale of such prospects. In April 2000, pursuant to the agreements, we acquired an approximate 25 percent working interest in the East Lawson Field in Acadia Parish, Louisiana. The acquisition included a 15 percent working interest in two producing oil and natural gas wells. During the year ended December 31, 2000, our share of the East Lawson Field production was 6,884 Bbls of oil and 43,352 Mcf of natural gas, resulting in income from United States oil and natural gas operations of $0.3 million. In December 2000, we sold our interest in the East Lawson Field for $0.8 million cash and a 5 percent carried working interest in up to four wells that may be drilled in the future. The agreement with Coastline was terminated on August 31, 2001. However, certain ongoing operations related to the Lakeside Exploration Prospect are conducted by Coastline on a continuing basis.

In March 1997, we acquired a 40 percent participation interest in three California State offshore oil and natural gas leases ("California Leases") from Molino Energy Company, LLC ("Molino Energy"), which held 100 percent of these leases. The project area covers the Molino, Gaviota and Caliente Fields, located approximately 35 miles west of Santa Barbara, California. In consideration of the 40 percent participation interest in the California Leases, we became the operator of the project and agreed to pay 100 percent of the first $3.7 million and 53 percent of the remainder of the costs of the first well drilled on the block. During 1998, the 2199 #7 exploratory well was drilled to the Gaviota anticline. Drill stem tests proved to be inconclusive or non-commercial, and the well was temporarily abandoned for further evaluation. In November 1998, we entered into an agreement to acquire Molino Energy's interest in the California Leases in exchange for the release of their joint interest billing obligations. In the fourth quarter of 1999, we decided to focus our capital expenditures on existing producing properties and fulfilling work commitments associated with our other properties. Because we had no firm approved plans to continue drilling on the California Leases and the 2199 #7 exploratory well did not result in commercial reserves, we wrote off 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. However, we continue to evaluate the prospect for potential future drilling activities.

Note 12 — China Operations

In December 1996, we acquired Benton Offshore China Company, a privately held corporation headquartered in Denver, Colorado, for 628,142 shares of common stock and options to purchase 107,571 shares of our common stock at $7.00 per share, valued in total at $14.6 million. Benton Offshore China Company's primary asset is a large undeveloped acreage position in the South China Sea under a petroleum contract with China National Offshore Oil Corporation ("CNOOC") of the People's Republic of China for an area known as Wan'An Bei, WAB-21. Benton Offshore China Company will, as our wholly owned subsidiary, continue as the operator and contractor of WAB-21. Benton Offshore China Company has submitted an exploration program and budget to CNOOC. However, due to certain territorial disputes over the sovereignty of the contract area, it is unclear when such program will commence.

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 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 and a consulting agreement with Mr. Benton pursuant to which we retained Mr. Benton as an independent contractor to perform certain services for us. During 2001, we paid Mr. Benton $116,833, and have paid a total of $536,545 from February 2000 through May 11, 2001 for services performed under the consulting agreement. On May 11, 2001, Mr. Benton and the Company entered into a settlement and release agreement under which the consulting agreement was terminated and Mr. Benton agreed to propose a plan of reorganization in his bankruptcy case that provides for the repayment of our loans to him. We currently continue to retain our security interest in Mr. Benton's 600,000 shares of our stock and in his stock options, and we have the right to vote the shares owned by him and to direct the exercise of his options. Repayment of our loans to Mr. Benton may be achieved through Mr. Benton's liquidation of certain real and personal property assets and a phased liquidation of stock resulting in Mr. Benton's exercise of his stock options. The amount that we eventually realize, and the timing of receipt of payments will depend upon the timing and results of the liquidation of Mr. Benton's assets. The amount of Mr. Benton's indebtedness to us is currently approximately $6.5 million. We continue to accrue interest at the rate of 6 percent per annum and record additional allowances as the interest accrues. The consulting agreement provides that if we close the Proposed Arctic Gas Sale, Mr. Benton will be entitled to receive two percent of our net after-tax cash receipts, actually received by us in the U.S., resulting from the Proposed Arctic Gas Sale, excluding any repayment of indebtedness or advances by us to Arctic Gas. The consulting agreement further provides that under his proposed bankruptcy plan of reorganization, Mr. Benton will pay five percent of such amounts to us. Based upon information provided by Mr. Benton's bankruptcy counsel, we anticipate that under the bankruptcy plan of reorganization that Mr. Benton will propose, we will receive $1.7 million. This amount does not include the amounts that we will realize from the exercise of Mr. Benton's options and the subsequent sale of the resulting shares, nor does it include the net proceeds that we will receive from the sale of Mr. Benton's 600,000 shares of our stock.

In May 2001, we entered into a Termination Agreement and a Consulting Agreement with our Chairman of the Board, Michael B. Wray. Under the Termination Agreement, Mr. Wray's employment relationship with us and any of our subsidiaries and affiliates terminated as of May 7, 2001. As consideration for entering into the Termination Agreement and settlement of all sums owed to Mr. Wray for his services as director through the 2001 Annual Meeting of Stockholders or as an employee, we paid Mr. Wray $100,000. Upon execution of the Termination Agreement, all stock options previously granted to Mr. Wray vested in their entirety. Additionally, under the terms of the Consulting Agreement, Mr. Wray received $100,000 and provided consulting services on matters pertaining to our business and that of our affiliates through December 31, 2001.

Note 14 — Earnings Per Share

In February 1997, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 128 ("SFAS 128") "Earnings per Share." SFAS 128 replaces the presentation of primary earnings per share with a presentation of basic earnings per share based upon the weighted average number of common shares for the period. Diluted earnings per share reflect the potential dilution that occurs if securities or other contracts were exercised or converted to common stock. It also requires dual presentation of basic and diluted earnings per share for companies with complex capital structures.

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 34.0 million, 30.7 million and 29.6 million for the years ended December 31, 2001, 2000 and 1999, 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 34.0 million, 30.9 million and 29.6 million for the years ended December 31, 2001, 2000 and 1999, respectively.

An aggregate of 6.7 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, 2001. For the years ended December 31, 2000 and 1999, 5.6 million and 6.2 million options and warrants, respectively, were excluded from the earnings per share calculations because they were anti-dilutive.

Note 15 — Reduction in Force and Corporate Restructuring

For 2001, we recorded non-recurring items of $11.4 million, $5.7 million of which are included in general and administrative expenses, $1.7 million of which are included in depletion, depreciation and amortization, $3.2 million in operating expenses and $0.8 in taxes other than income. The general and administrative expenses include $2.2 million on the failed debt exchange, $2.2 million for severance and termination benefits for 33 employees, $1.1 million for lease relinquishment expenses, and $0.2 million for relocation costs to Houston. Depletion, depreciation and amortization included $0.9 million for the reduction in the carrying value of fixed assets that were not transferred to Houston and $0.8 million loss on subleasing the former Carpinteria headquarters. All expenses were paid or accrued by December 31, 2001. The accrued balance of $0.1 million will be paid in 2002.

Note 16 — Subsequent Event — Sale of Arctic Gas Company

On February 27, 2002, we entered into a Sale and Purchase Agreement ("Transaction") to sell our 68 percent interest in Arctic Gas Company to a nominee of the Yukos Oil Company for $190 million plus approximately $30 million as repayment of intercompany loans owed to us by Arctic Gas. We intend to retire all of our $108 million outstanding 11⅝ percent senior notes in accordance with their terms, which alone eliminates a substantial interest burden and removes a near-term concern regarding the Company's liquidity. The remaining net proceeds and cash received from the repayment of loans will be used to further reduce debt from time to time, accelerate strategic growth of our remaining assets in Venezuela and Russia, and for general corporate purposes. On March 22, 2002, we were notified that the Transaction had received the requisite consents from the Russian Ministry for Antimonopoly Policy and Support for Entrepreneurship. On March 28, 2002, we received the first payment ($120.0 million) of the Proposed Arctic Gas Sale proceeds. We expect that all aspects of the Transaction will be completed by April 2002. However, in the event we do not close the Transaction, we will be required to review additional strategic alternatives to repay the $108 million of 11⅝ percent senior notes due May 2003.

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, 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

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(Amounts in thousands, except per share data)			
Year ended December 31, 2000				
Revenues	$ 31,433	$ 32,111	$ 37,972	$ 38,768
Expenses	(18,647)	(22,357)	(22,270)	(23,806)
Non-operating expense	(5,248)	(5,201)	(5,017)	(4,622)
Income from consolidated companies before income taxes and minority interests	7,538	4,553	10,685	10,340
Income tax expense	4,636	3,656	5,018	722
Income before minority interests	2,902	897	5,667	9,618
Minority interests	1,634	1,336	2,007	2,892
Income (loss) from consolidated companies	1,268	(439)	3,660	6,726
Equity in earnings of affiliated companies	1,727	177	2,213	1,196
Income (loss) before extraordinary income	2,995	(262)	5,873	7,922
Extraordinary income on debt repurchase	—	—	3,095	865
Net income (loss)	$ 2,995	$ (262)	$ 8,968	$ 8,787
Net income (loss) per common share:				
Basic and Diluted	$ 0.10	$ (0.01)	$ 0.29	$ 0.26

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:

	Consolidated Companies				Equity Affiliates	
	Venezuela	China	United States and Other	Subtotal	Russia	Total
	(In thousands)					
Year Ended December 31, 2001						
Development costs	$35,194	$ 77	$ 28	$35,299	$13,580	$48,879
Exploration costs	7,694	—	909	8,603	8,136	16,739
	$42,888	$ 77	$ 937	$43,902	$21,716	$65,618
Year Ended December 31, 2000						
Acquisition costs	$ —	$ —	$ 170	$ 170	$ —	$ 170
Development costs	47,604	—	—	47,604	13,887	61,491
Exploration costs	94	84	2,470	2,648	4,206	6,854
	$47,698	$ 84	$2,640	$50,422	$18,093	$68,515
Year Ended December 31, 1999						
Development costs	$22,361	$ —	$ 104	$22,465	$ 6,342	$28,807
Exploration costs	261	8,480	1,761	10,502	1,345	11,847
	$22,622	$8,480	$1,865	$32,967	$ 7,687	$40,654

Table II

Capitalized costs related to oil and natural gas producing activities:

	Consolidated Companies				Equity Affiliates	
	Venezuela	China	United States and Other	Subtotal	Russia	Total
	(In thousands)					
December 31, 2001						
Proved property costs	$ 469,218	$ 12,892	$ 19,813	$ 501,923	$ 91,463	$ 593,386
Costs excluded from amortization	—	16,248	560	16,808	11,549	28,357
Oilfield inventories	15,219	—	—	15,219	4,532	19,751
Less accumulated depletion and impairment	(361,313)	(12,892)	(19,544)	(393,749)	(32,684)	(426,433)
	$ 123,124	$ 16,248	$ 829	$ 140,201	$ 74,860	$ 215,061
December 31, 2000						
Proved property costs	$ 426,330	$ 12,879	$ 19,362	$ 458,571	$ 85,086	$ 543,657
Costs excluded from amortization	—	16,183	451	16,634	6,536	23,170
Oilfield inventories	15,343	—	—	15,343	2,705	18,048
Less accumulated depletion and impairment	(339,542)	(12,879)	(19,090)	(371,511)	(27,249)	(398,760)
	$ 102,131	$ 16,183	$ 723	$ 119,037	$ 67,078	$ 186,115
December 31, 1999						
Proved property costs	$ 378,631	$ 12,870	$ 18,025	$ 409,526	$ 68,526	$ 478,052
Costs excluded from amortization	—	16,108	9	16,117	5,004	21,121
Oilfield inventories	9,806	—	—	9,806	2,084	11,890
Less accumulated depletion and impairment	(324,211)	(12,870)	(17,753)	(354,834)	(24,102)	(378,936)
	$ 64,226	$ 16,108	$ 281	$ 80,615	$ 51,512	$ 132,127

Table III

Results of operations for oil and natural gas producing activities:

	Consolidated Companies			Equity Affiliates	
	Venezuela	United States and Other	Subtotal	Russia	Total
			(In thousands)		
Year ended December 31, 2001					
Oil sales	$122,386	$ —	$122,386	$38,410	$160,796
Expenses:					
Operating, selling and distribution expenses and taxes other than on income	42,212	722	42,934	19,934	62,868
Depletion	22,119	—	22,119	5,367	27,486
Write-down of oil and gas properties and impairments	—	468	468	—	468
Income tax expense	11,156	13	11,169	3,238	14,407
Total expenses	75,487	1,203	76,690	28,539	105,229
Results of operations from oil and natural gas producing activities	$ 46,899	$ (1,203)	$ 45,696	$ 9,871	$ 55,567
Year ended December 31, 2000					
Oil and natural gas sales	$139,890	$ 394	$140,284	$26,091	$166,375
Expenses:					
Operating, selling and distribution expenses and taxes other than on income	46,879	731	47,610	10,152	57,762
Depletion	15,331	45	15,376	3,305	18,681
Write-down of oil and gas properties and impairments	—	1,346	1,346	—	1,346
Income tax expense	20,398	12	20,410	3,275	23,685
Total expenses	82,608	2,134	84,742	16,732	101,474
Results of operations from oil and natural gas producing activities	$ 57,282	$ (1,740)	$ 55,542	$ 9,359	$ 64,901
Year ended December 31, 1999					
Oil sales	$ 89,060	$ —	$ 89,060	$11,006	$100,066
Expenses:					
Operating, selling and distribution expenses and taxes other than on income	38,841	710	39,551	4,139	43,690
Depletion	14,829	—	14,829	3,325	18,154
Write-down of oil and gas properties and impairments	—	25,891	25,891	—	25,891
Income tax expense	3,812	638	4,450	436	4,886
Total expenses	57,482	27,239	84,721	7,900	92,621
Results of operations from oil and natural gas producing activities	$ 31,578	$(27,239)	$ 4,339	$ 3,106	$ 7,445

Geoilbent (34 percent ownership by us) and Arctic Gas (39 percent, 29 percent and 24 percent ownership not subject to certain sale and transfer restrictions at December 31, 2001, 2000 and 1999, 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, 2001, 2000 and 1999.

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, 2001 and 2000 were prepared by Ryder-Scott, independent petroleum engineers. The evaluations of the oil and natural gas reserves as of December 31, 1999 were audited by Huddleston & Co., Inc., independent petroleum engineers.

	Consolidated Companies				Equity Affiliates	
	United States	Venezuela	Minority Interest in Venezuela	Net Total	Russia	Total
Proved Reserves-Crude oil, condensate, and natural gas liquids (MBbls)						
Year ended December 31, 2001						
Proved reserves beginning of the year	—	123,039	(24,608)	98,431	48,435	146,866
Revisions of previous estimates	—	(8,747)	1,749	(6,998)	(54)	(7,052)
Extensions, discoveries and improved recovery	—	—	—	—	4,411	4,411
Production	—	(9,778)	1,956	(7,822)	(2,160)	(9,982)
Proved reserves end of year	—	104,514	(20,903)	83,611	50,632	134,243
Year ended December 31, 2000						
Proved reserves beginning of the year	—	134,961	(26,992)	107,969	40,129	148,098
Revisions of previous estimates	—	(8,826)	1,765	(7,061)	(2,811)	(9,872)
Purchases of reserves in place	15	—	—	15	—	15
Extensions, discoveries and improved recovery	—	6,268	(1,254)	5,014	12,610	17,624
Production	(7)	(9,364)	1,873	(7,498)	(1,493)	(8,991)
Sales of reserves in place	(8)	—	—	(8)	—	(8)
Proved reserves end of year	—	123,039	(24,608)	98,431	48,435	146,866
Year ended December 31, 1999						
Proved reserves beginning of the year	—	137,835	(27,567)	110,268	31,053	141,321
Revisions of previous estimates	—	(7,488)	1,498	(5,990)	(531)	(6,521)
Extensions, discoveries and improved recovery	—	14,281	(2,856)	11,425	11,058	22,483
Production	—	(9,667)	1,933	(7,734)	(1,451)	(9,185)
Proved reserves end of year	—	134,961	(26,992)	107,969	40,129	148,098
Proved Developed Reserves at:						
December 31, 2001	—	51,465	(10,293)	41,172	18,141	59,313
December 31, 2000	—	67,217	(13,443)	53,774	17,238	71,012
December 31, 1999	—	67,118	(13,423)	53,695	15,120	68,815
December 31, 1998	—	75,636	(15,127)	60,509	9,745	70,254
Proved reserves-natural gas (MMcf)						
Year ended December 31, 2001						
Proved reserves beginning of the year	—	—	—	—	152,496	152,496
Revisions of previous estimates	—	—	—	—	55,514	55,514
Proved reserves end of the year	—	—	—	—	208,010	208,010
Proved Developed Reserves at:						
December 31, 2001	—	—	—	—	21,292	21,292
December 31, 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.

Excise, pipeline and other tariffs and taxes continue to be levied on all oil producers and certain exporters, including an oil export tariff that decreased to $8.00 per ton (approximately $1.10 per barrel) from 23.4 Euros per ton (approximately $2.85 per barrel). We are unable to predict the impact of taxes, duties and other burdens for the future for our Russian operations.

	Consolidated Companies			Equity Affiliates	
	Venezuela	Minority Interest in Venezuela	Net Total	Russia	Total
	(Amounts in thousands)				
December 31, 2001					
Future cash inflow	$1,030,404	$(206,081)	$ 824,323	$1,064,688	$ 1,889,011
Future production costs	(558,431)	111,686	(446,745)	(624,793)	(1,071,538)
Future development costs	(142,006)	28,401	(113,605)	(86,159)	(199,764)
Future net revenue before income taxes	329,967	(65,994)	263,973	353,736	617,709
10% annual discount for estimated timing of cash flows	(109,704)	21,941	(87,763)	(164,211)	(251,974)
Discounted future net cash flows before income taxes	220,263	(44,053)	176,210	189,525	365,735
Future income taxes, discounted at 10% per annum	(16,103)	3,221	(12,882)	(36,672)	(49,554)
Standardized measure of discounted future net cash flows	$ 204,160	$ (40,832)	$ 163,328	$ 152,853	$ 316,181

	Consolidated Companies			Equity Affiliates	
	Venezuela	Minority Interest in Venezuela	Net Total	Russia	Total
	(Amounts in thousands)				
December 31, 2000					
Future cash inflow	$1,505,870	$(301,174)	$1,204,696	$1,273,327	$ 2,478,023
Future production costs	(618,870)	123,774	(495,096)	(811,678)	(1,306,774)
Future development costs	(166,039)	33,208	(132,831)	(70,620)	(203,451)
Future net revenue before income taxes	720,961	(144,192)	576,769	391,029	967,798
10% annual discount for estimated timing of cash flows	(260,381)	52,076	(208,305)	(176,352)	(384,657)
Discounted future net cash flows before income taxes	460,580	(92,116)	368,464	214,677	583,141
Future income taxes, discounted at 10% per annum	(104,894)	20,979	(83,915)	(43,072)	(126,987)
Standardized measure of discounted future net cash flows	$ 355,686	$ (71,137)	$ 284,549	$ 171,605	$ 456,154
December 31, 1999					
Future cash inflow	$1,727,228	$(345,446)	$1,381,782	$ 566,201	$ 1,947,983
Future production costs	(543,976)	108,795	(435,181)	(150,370)	(585,551)
Future development costs	(144,639)	28,928	(115,711)	(38,210)	(153,921)
Future net revenue before income taxes	1,038,613	(207,723)	830,890	377,621	1,208,511
10% annual discount for estimated timing of cash flows	(386,930)	77,386	(309,544)	(154,032)	(463,576)
Discounted future net cash flows before income taxes	651,683	(130,337)	521,346	223,589	744,935
Future income taxes, discounted at 10% per annum	(175,602)	35,121	(140,481)	(47,676)	(188,157)
Standardized measure of discounted future net cash flows	$ 476,081	$ (95,216)	$ 380,865	$ 175,913	$ 556,778

Table VI

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

	Consolidated Companies			Equity Affiliates			Total		
	2001	2000	1999	2001	2000	1999	2001	2000	1999
	(Amounts in thousands)								
Present Value at January 1	$ 284,549	$ 380,865	$ 49,964	$171,605	$175,913	$ 43,248	$ 456,154	$ 556,778	$ 93,212
Sales of oil and natural gas, net of related costs	(64,139)	(58,913)	(40,303)	(19,001)	(20,977)	(3,238)	(83,140)	(79,890)	(43,541)
Revisions to estimates of proved reserves									
Net changes in prices, development and production costs	(141,429)	(124,402)	552,614	(39,880)	(72,740)	120,742	(181,309)	(197,142)	673,356
Quantities	(26,198)	(26,494)	(26,671)	8,881	(19,685)	(2,858)	(17,317)	(46,179)	(29,529)
Sales of reserves in place	—	—	—	—	—	—	—	—	—
Extensions, discoveries and improved recovery, net of future costs	—	16,429	65,184	18,767	73,542	54,326	18,767	89,971	119,510
Accretion of discount	36,846	52,135	4,996	21,468	22,359	4,955	58,314	74,494	9,951
Net change in income taxes	71,033	56,567	(140,481)	6,400	4,604	(41,378)	77,433	61,171	(181,859)
Development costs incurred	23,768	36,210	28,558	17,110	8,475	4,370	40,878	44,685	32,928
Changes in timing and other	(21,102)	(47,848)	(112,996)	(32,497)	114	(4,254)	(53,599)	(47,734)	(117,250)
Present Value at December 31	$ 163,328	$ 284,549	$ 380,865	$152,853	$171,605	$175,913	$ 316,181	$ 456,154	$ 556,778

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, 2002.

BENTON OIL AND GAS COMPANY
(Registrant)

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

Date: March 28, 2002

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, 2002, 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/ BYRON A. DUNN Byron A. Dunn	Director
/s/ H.H. HARDEE H.H. Hardee	Director
/s/ PATRICK M. MURRAY Patrick M. Murray	Director

SCHEDULE II

BENTON OIL AND GAS COMPANY AND SUBSIDIARIES

VALUATION AND QUALIFYING ACCOUNTS

	Balance at Beginning of Year	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions From Reserves	Balance at End of Year
			(In thousands)		
At December 31, 2001					
Amounts deducted from applicable assets					
Accounts receivable	$ 6,518	$ 330	$ —	$ 336	$ 6,512
Valuation allowances	54,207	14,352	(11,008)	37,851	19,700
Investment at cost	1,350	—	—	—	1,350
At December 31, 2000					
Amounts deducted from applicable assets					
Accounts receivable	$ 6,187	$ 331	—	—	$ 6,518
Valuation allowances	51,913	2,446	—	152	54,207
Investment at cost	1,350	—	—	—	1,350
At December 31, 1999					
Amounts deducted from applicable assets					
Accounts receivable	$ 3,236	$ 858	2,093	—	$ 6,187
Valuation allowances	45,962	14,541	—	8,590	51,913
Investment at cost	—	1,350	—	—	1,350
Reserves included in stockholders' equity					
Allowance for employee note secured by Benton Oil and Gas Company stock	2,093	—	(2,093)	—	—

Officers

DR. PETER J. HILL
PRESIDENT AND CHIEF EXECUTIVE OFFICER

STEVEN W. THOLEN
SENIOR VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

ROBERT S. MOLINA
VICE PRESIDENT, GENERAL COUNSEL AND SECRETARY

KURT A. NELSON
VICE PRESIDENT AND CONTROLLER

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.

BYRON A. DUNN
EXECUTIVE DIRECTOR, INVESTMENT BANKING
UBS WARBURG, LLC

H.H. "WILL" HARDEE
SENIOR VICE PRESIDENT, INVESTMENT OFFICER RBC
DAIN RAUSCHER, INC.

DR. PETER J. HILL
PRESIDENT AND CHIEF EXECUTIVE OFFICER
BENTON OIL AND GAS COMPANY

PATRICK M. MURRAY
PRESIDENT AND CHIEF EXECUTIVE OFFICER
DRESSER, INC.

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 14, 2002 AT 9:00 A.M.
DOUBLETREE HOTEL – ALLEN CENTER
400 DALLAS STREET
HOUSTON, TX 77002

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:

BENTON OIL AND GAS COMPANY
15835 PARK TEN PLACE DRIVE
SUITE 115
HOUSTON, TX 77084

(281) 579-6700
(281) 579-6702 FACSIMILE
E-MAIL: INVESTORRELATIONS@BOGC.COM

Benton Stock

BENTON OIL AND GAS COMPANY'S STOCK IS TRADED ON THE NEW YORK STOCK EXCHANGE (NYSE) UNDER THE SYMBOL BNO.

Corporate Web Site

WWW.BENTONOIL.COM

DESIGN BY: PEGASUS DESIGN, INC. WWW.PEGASUSDESIGN.COM