VINTAGE PETROLEUM INC
Form 10-K
March 12, 2001

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2000

OR

[_] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 1-10578

VINTAGE PETROLEUM, INC.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	73-1182669 (I.R.S. Employer Identification No.)
110 West Seventh Street Tulsa, Oklahoma (Address of principal executive offices)	74119-1029 zip code

Registrant's telephone number, including area code: (918) 592-0101

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

Title of each class	Name of each exchange on which registered
Common Stock, $.005 Par Value	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No _____

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the 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.[_]

As of February 28, 2001, 62,890,416 shares of the Registrant's Common Stock were outstanding, and the aggregate market value of the Common Stock held by non-affiliates was approximately $987,332,000.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement for the Annual Meeting of Stockholders to be held May 8, 2001, are incorporated by reference into Part III of this Form 10-K.

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Certain Definitions

As used in this Form 10-K:

Unless the context requires otherwise, all references to the "Company" include Vintage Petroleum, Inc., its consolidated subsidiaries and its proportionately consolidated general partner interests in various joint ventures.

"Mcf" means thousand cubic feet, "MMcf" means million cubic feet, "Bcf" means billion cubic feet, "Tcf" means trillion cubic feet, "BCFE" means billion cubic feet of gas equivalent, "MMBtu" means million British thermal units, "Bbl" means barrel, "MBbls" means thousand barrels, "MMBbls" means million barrels, "BOE" means equivalent barrels of oil, "MBOE" means thousand equivalent barrels of oil and "MMBOE" means million equivalent barrels of oil.

Unless otherwise indicated in this Form 10-K, gas volumes are stated at the legal pressure base of the state or area in which the reserves are located and at 60 Fahrenheit. Equivalent barrels of oil are determined using the ratio of six Mcf of gas to one Bbl of oil.

The term "gross" refers to the total acres or wells in which the Company has a working interest, and "net" refers to gross acres or wells multiplied by the percentage working interest owned by the Company. "Net production" means production that is owned by the Company less royalties and production due others.

"Proved oil and gas 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 reservoirs under existing economic and operating conditions. "Proved developed oil and gas reserves" are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. "Proved undeveloped oil and gas reserves" ("PUD") are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Forward-Looking Statements

This Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in this Form 10-K which address activities, events or developments which the Company expects or anticipates will or may occur in the future are forward-looking statements. The words "believes," "intends," "expects," "anticipates," "projects," "estimates," "predicts" and similar expressions are also intended to identify forward-looking statements.

These forward-looking statements include, among others, such things as:

- the amount and nature of future capital expenditures;
- wells to be drilled or reworked;
- oil and gas prices and demand;
- exploitation and exploration prospects;
- estimates of proved oil and gas reserves;
- reserve potential;
- development and infill drilling potential;
- expansion and other development trends of the oil and gas industry;
- business strategy;
- production of oil and gas reserves; and
- expansion and growth of our business and operations.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate in the circumstances. However, whether actual results and developments will conform with the Company's expectations and predictions is subject to a number of risks and uncertainties which could cause actual results to differ materially from the Company's expectations, including:

- the risk factors discussed in this Form 10-K and listed from time to time in the Company's filings with the Securities and Exchange Commission;
- oil and gas prices;
- exploitation and exploration successes;
- continued availability of capital and financing;
- general economic, market or business conditions;
- the acquisition and other business opportunities (or lack thereof) that may be presented to and pursued by the Company;
- changes in laws or regulations; and
- other factors, most of which are beyond the control of the Company.

Consequently, all of the forward-looking statements made in this Form 10-K are qualified by these cautionary statements and there can be no assurance that the actual results or developments anticipated by the Company will be realized or, even if substantially realized, that they will have the expected consequences to or effects on the Company or its business or operations. The Company assumes no obligation to update publicly any such forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Items 1 and 2. Business and Properties.

General

The Company is an independent oil and gas company focused on the acquisition of oil and gas properties which contain the potential for increased value through exploitation and exploration. The Company, through its experienced management and technical staff, has been successful in realizing such potential on prior acquisitions through workovers, recompletions, secondary recovery operations, operating cost reductions, and the drilling of development or exploratory wells. The Company believes that its primary strengths are its ability to add reserves at attractive prices, its technical expertise and its low cost operating structure.

At December 31, 2000, the Company owned and operated producing properties in 11 states in the United States, with its domestic proved reserves located primarily in four core areas: the Gulf Coast, East Texas, Mid-Continent and West Coast areas of the United States. During 2000, the Company expanded its North American operations into Canada through the acquisition of 100 percent of Cometra Energy (Canada), Ltd. (now Vintage Energy (Canada), Ltd.). See "Acquisition Activities." In addition, the Company has international core areas located in Argentina, Bolivia and Ecuador. In Argentina, the Company owns 15 oil concessions, 14 of which are operated by the Company, in the south flank of the San Jorge Basin in southern Argentina. During 2000, the Company expanded this core area with the purchase of the Piedras Colorados and Cachueta concessions in the Cuyo Basin in western Argentina. See "Acquisition Activities." In Bolivia, the Company owns and operates three blocks covering approximately 570,000 acres in the Chaco Plains area of southern Bolivia and the Naranjillos concession located in the Santa Cruz Province. In November 1998, the Company purchased, through a wholly-owned subsidiary, a subsidiary of Elf Aquitaine with operations in Ecuador. This subsidiary currently operates producing properties in the Oriente Basin in Ecuador and provides the Company with substantial undeveloped acreage which the Company believes has significant development and exploration potential.

As of December 31, 2000, the Company owned interests in 3,592 gross (2,827 net) productive wells in the United States, of which approximately 84 percent are operated by the Company, 1,301 gross (1,285 net) productive wells in Argentina, of which approximately 98 percent are operated by the Company, 16 gross (15 net) productive wells in Bolivia, 100 percent of which are operated by the Company, 8 gross (6 net) productive wells in Ecuador, 100 percent of which are operated by the Company, and 156 gross (78 net) productive wells in Canada, of which approximately 50 percent are operated by the Company. As of December 31, 2000, the Company's properties had proved reserves of 489.1 MMBOE, comprised of 318.6 MMBbls of oil and 1.0 Tcf of gas, with a present value of estimated future net revenues before income taxes (utilizing a 10 percent discount rate) of $4.3 billion and a standardized measure of discounted future net cash flows of $3.0 billion. From the first quarter of 1998 through the fourth quarter of 2000, the Company increased its average net daily production from 45,000 Bbls of oil to 59,900 Bbls of oil and from 128,500 Mcf of gas to 161,300 Mcf of gas.

Financial information relating to the Company's industry segments is set forth in Note 7 "Segment Information" to the Company's consolidated financial statements included elsewhere in this Form 10-K.

The Company was incorporated in Delaware on May 31, 1983. The Company's principal office is located at 110 West Seventh Street, Tulsa, Oklahoma 74119-1029, and its telephone number is (918) 592-0101.

Business Strategy

The Company's overall goal is to maximize its value through profitable growth in its oil and gas reserves and production. The Company has been successful at achieving this goal through its ongoing strategy of (a) acquiring producing oil and gas properties, at favorable prices, with significant upside potential, (b) focusing on exploitation, development and exploration activities to maximize production and ultimate reserve recovery on existing properties, (c) exploring undeveloped properties, (d) maintaining a low cost operating structure and (e) maintaining financial flexibility. Key elements of the Company's strategy include:

- Acquisitions of Producing Properties. The Company has an experienced management and technical team which focuses on acquisitions of operated producing properties that meet its selection criteria which include (a) significant potential for increasing reserves and production through exploitation, development and exploration, (b) attractive purchase price and (c) opportunities for improved operating efficiency. The Company's emphasis on property acquisitions reflects its belief that continuing consolidation and restructuring activities on the part of major integrated and large independent oil companies has afforded in recent years, and should afford in the future, attractive opportunities to purchase domestic and international properties. This acquisition strategy has allowed the Company to rapidly grow its reserves at favorable acquisition prices. From January 1, 1998, through December 31, 2000, the Company acquired 152.0 MMBOE of proved oil and gas reserves at an average acquisition cost of $2.39 per BOE. The Company replaced through acquisitions approximately 195 percent of its production of 78.1 MMBOE during the same period. The Company is continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than those consummated to date by the Company. No assurance can be given that any such acquisitions will be successfully consummated.

. Exploitation and Development. The Company pursues workovers, recompletions, secondary recovery operations and other production optimization techniques on its properties, as well as development and infill drilling, to offset normal production declines and replace the Company's annual production. From January 1, 1998, through December 31, 2000, the Company spent approximately $216.8 million on exploitation and development activities. As a result of all of its exploitation activities, including development and infill drilling, during the three-year period ended December 31, 2000, the Company succeeded in adding 88.2 MMBOE to proved reserves, replacing approximately 113 percent of production during this period. During 2000, the Company added 22.2 MMBOE through exploitation, replacing 77 percent of production. The Company continues to maintain an extensive inventory of exploitation and development opportunities. Due to the continued strong product price environment, the Company anticipates increasing its level of spending to approximately $212 million in 2001 on exploitation and development projects, primarily in the United States and Argentina.

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. Exploration. The Company's overall exploration strategy balances high potential international prospects with lower risk drilling in known formations in the United States and Argentina. This prospect mix and the Company's practice of risk-sharing with industry partners is intended to lower the incidence and costs of dry holes. The Company makes extensive use of geophysical studies, including 3-D seismic, which further reduces the cost by increasing the success of its exploration program. From January 1, 1998, through December 31, 2000, the Company spent approximately $201.4 million on exploration activities, including $40.9 million on undeveloped leasehold and exploratory drilling in progress which was unevaluated at December 31, 2000. The Company drilled 81 gross (48.37 net) exploration wells, of which approximately 58 percent gross (66 percent net) were productive. As a result of all of the Company's exploration activities during the three-year period ended December 31, 2000, the Company succeeded in adding 55.4 MMBOE to proved reserves, replacing approximately 71 percent of production during this period. The Company's exploration activities in 2000 were focused on its core areas in the United States, Bolivia, Ecuador and Yemen. The Company anticipates 2001 spending of approximately $73 million on exploration projects, primarily in the United States, Canada, Yemen and Trinidad.

- Low Cost Structure. The Company is an efficient operator and capitalizes on its low cost structure in evaluating acquisition opportunities. The Company generally achieves substantial reductions in labor and other field level costs from those experienced by the previous operators. In addition, the Company targets acquisition candidates which are located in its core areas and provide opportunities for cost efficiencies through consolidation with other Company operations. The lower cost structure has generally allowed the Company to substantially improve the cash flow of newly acquired properties.

- Financial Flexibility. The Company is committed to maintaining financial flexibility, which management believes is important for the successful execution of its acquisition, exploitation and exploration strategy. Since 1990, the Company has completed five public equity offerings, two public debt offerings and a Rule 144A private debt offering, all of which have provided the Company with aggregate net proceeds of approximately $643 million. During 2000, the Company applied excess cash flow over capital expenditures to substantially reduce outstanding long-term debt, lowering its net long-term debt-to-book capitalization ratio from 57.5 percent at December 31, 1999, to 41.6 percent at December 31, 2000. The unused portion of the Company's revolving credit facility at February 28, 2001, of approximately $511 million and its strong balance sheet provide the Company flexibility to capitalize on significant acquisition opportunities.

Acquisition Activities

Historically, the Company has allocated a substantial portion of its capital expenditures to the acquisition of producing oil and gas properties. The Company's continuing emphasis on reserve additions through property acquisitions reflects its belief that consolidation and restructuring activities on the part of major integrated and large independent oil companies has afforded in recent years, and should afford in the future, attractive opportunities to purchase domestic and international producing properties.

Since the Company's incorporation in May 1983, it has been actively engaged in the acquisition of producing oil and gas properties primarily in the Gulf Coast, East Texas and Mid-Continent areas of the United States, and in California since April 1992. In 1995, a series of acquisitions made by the Company established a new core area in the San Jorge Basin in southern Argentina. In late 1996, the Company expanded its South American operations into Bolivia and in 1998 into Ecuador. In 1999, the Company entered into a farm-in agreement for the S-1 Damis exploration block in Yemen and in December 2000, made its initial entrance into Canada with the purchase of 100 percent of Cometra Energy (Canada), Ltd., a privately-held Canadian company. The Company also extended its Argentina operations into western Argentina with its September 2000 acquisition of two concessions from Perez Companc. The Company is constantly identifying and evaluating additional acquisition opportunities which may lead to expansion into new domestic core areas or other countries which the Company believes are politically and economically stable.

From January 1, 1998, through December 31, 2000, the Company made oil and gas property acquisitions involving total costs of

approximately $363.3 million. As a result of these acquisitions, the Company acquired approximately 152.0 MMBOE of proved oil and gas reserves. The following table summarizes the Company's acquisition experience during the periods indicated:

	Acquisition Costs	Proved Reserves When Acquired Oil (MBbls)	Gas (MMcf)	MBOE	Cost Per Boe When Acquired
	(In thousands)				
North America Acquisitions:					
1998	$ 70,805	5,452	53,027	14,290	$ 4.95
1999	31,662	10,343	14,947	12,834	2.47
2000	53,962	2,854	41,166	9,715	5.55
Total North America Acquisitions	156,429	18,649	109,140	36,839	4.25
South America Acquisitions:					
1998	34,218	21,577	-	21,577	1.59
1999	135,125	67,734	81,072	81,246	1.66
2000	37,486	11,970	2,278	12,350	3.04
Total South America Acquisitions	206,829	101,281	83,350	115,173	1.80
Total Acquisitions	$ 363,258	119,930	192,490	152,012	$ 2.39

The Company estimates that 22.1 MMBOE of proved reserves, as of the various acquisition dates, were acquired in 2000 for an aggregate cost attributable to oil and gas assets of $91.4 million, resulting in an average cost of $4.14 per BOE. The average cost per BOE over the three-year period ended December 31, 2000, is $2.39 and the cost since the Company's inception is $2.97 per BOE.

The following is a brief discussion of the significant acquisitions in 2000:

Cuyo Basin Properties (Argentina). In September 2000, the Company purchased an interest in two concessions in the Cuyo Basin (the "Cuyo Properties"), covering approximately 204,000 acres in Mendoza Province of western Argentina. The Company purchased 100 percent of the interest formerly held by Perez Companc for $40.1 million in cash funded through an advance under the Company's unsecured revolving credit facility.

The Cuyo Properties had current net daily production at the time of the acquisition of 2,000 Bbls of 32 degree gravity, light, sweet crude oil and are similar in production and operating characteristics to the Company's existing operations in the San Jorge Basin of southern Argentina. Exploitation activities aimed at increasing production are targeted to begin in the second quarter of 2001.

This acquisition marks the Company's entry as an operator into the western basins of Argentina and is consistent with its long-term objective of expanding the Company's presence in Argentina. The Company plans to apply 3-D seismic-driven development drilling and cost reduction strategies that have proven successful for it in the San Jorge Basin in Argentina and the U.S. to the Cuyo Properties. Some of the cost reduction strategies have already been initiated.

Cometra Energy (Canada), Ltd. (North America). In December 2000, the Company acquired 100 percent of the outstanding common stock of Cometra Energy (Canada), Ltd. ("Cometra") from Electrafina, a part of Groupe Brussels Lambert SA, for approximately $46.2 million (CAD $71.0 million) and the assumption of estimated net liabilities of approximately $7.6 million (CAD $11.6 million) (the "Cometra Acquisition"). The purchase was funded through an advance under the Company's unsecured revolving credit facility.

The Cometra Acquisition contains properties consisting primarily of 13 producing fields, principally in the provinces of Alberta

and British Columbia with additional fields in Saskatchewan, certain processing and pipeline facilities and approximately 126 thousand net undeveloped acres. Additionally, through a wholly-owned subsidiary of Cometra, the Company also has a 36 percent working interest in an exploration concession in Trinidad representing approximately 10,000 net undeveloped acres. The Company operates approximately 50 percent of the wells, which had a total net daily production at the time of the acquisition averaging approximately 12 MMcf and 635 Bbls of light crude oil, or a combined 2,670 BOE. The realized oil price for the production averaged approximately 93 percent of the NYMEX price, while the average price of gas is approximately 67 percent of the NYMEX reference price of gas.

The Cometra Acquisition marks the Company's initial entry into Canada and Trinidad. It also establishes western Canada as a new core area for the Company, complementing its existing core operating areas in the U.S., Argentina, Bolivia and Ecuador.

The Company anticipates spending approximately $14.3 million in 2001 for identified exploitation and exploration projects arising from the acquisition, primarily in Canada. In addition, an exploration commitment is also in place to drill three wells in the long established productive region of southern onshore Trinidad through a wholly-owned subsidiary of Cometra.

Divestiture Activities

During 1999, the Company instituted a divestiture program designed to sell Company properties that were either marginally economical or non-strategic to the Company's areas of operation. As part of this program, the Company sold approximately 227 leases, primarily non-operated, for cash proceeds of approximately $9.5 million resulting in gains of $7.7 million ($4.7 million after tax). The Company estimates the properties sold accounted for proved reserves of approximately 2.6 Bcf of gas and 577 MBbls of oil as of the closing dates for these sales.

During December 1999, the Company sold its interest in certain oil and gas properties located in northern California's Sacramento Basin to Calpine Corporation for $70.0 million, subject to consents and customary post-closing adjustments. In a separate transaction with an undisclosed buyer, the Company sold certain royalty interests in Los Angeles County, California for $8.2 million. Combined, the Company estimates the properties sold accounted for proved reserves of approximately 32.1 Bcf of gas and 682 MBbls of oil as of the closing dates for these sales. Net daily production from the properties sold totaled approximately 250 Bbls of oil and 14.3 MMcf of gas, or approximately 3.5 percent of the Company's net average daily production rate on a BOE basis for the fourth quarter of 1999. The sale of these properties have not had a material impact on the Company's continuing operations. A portion of the proceeds from these property sales was used to fund the acquisition of certain producing oil and gas properties from Nuevo Energy Company (the "Nuevo Acquisition") and the proceeds in excess of the Nuevo Acquisition costs were used to reduce a portion of the Company's outstanding debt. The sales resulted in $47.3 million in gains ($28.9 million after tax) which were included in the Company's 1999 operating results.

Exploitation and Development

The Company concentrates its acquisition efforts on proved producing properties which demonstrate a potential for significant additional development through workovers, recompletions, secondary recovery operations, the drilling of development, infill or exploratory wells and other exploitation opportunities. The Company has pursued an active workover, recompletion and development drilling program on the properties it has acquired and intends to continue these activities in the future.

The Company's exploitation staff focuses on maximizing the value of the properties within its reserve base striving to offset normal production declines and to replace the Company's annual production. The results of their efforts are reflected in revisions to reserves. Net revisions to reserves for 2000 totaled 22.2 MMBOE, or 77 percent of the Company's production of 28.8 MMBOE.

As a result of the return of higher oil and gas prices, the Company spent $25.8 million on workover and recompletion operations during 2000, significantly higher than 1999. A measure of the overall success of the Company's recompletion and workover operations during 2000 (excluding minor equipment repair and replacement) was that improved production or operating efficiencies were achieved from approximately 81 percent of such operations consistent with the average for the last three years of 79 percent.

Development drilling activity is generated both through the Company's exploration efforts and as a result of obtaining undeveloped acreage in connection with producing property acquisitions. In addition, there are many opportunities for infill drilling on Company leases currently producing oil and gas. The Company intends to continue to pursue development drilling opportunities which offer potentially significant returns to the Company.

During 2000, the Company participated in the drilling of 64 gross (57.61 net) development wells, of which 61 gross (54.93 net) were productive. At December 31, 2000, the Company's proved reserves included approximately 145 development or infill drilling locations on its U.S. acreage, 212 locations on its Argentina acreage, 44 locations on its Ecuador acreage, 25 locations on its Canada acreage and 16 locations on its Bolivia acreage. In addition, the Company has an extensive inventory of development and infill drilling locations on its existing properties which are not included in proved reserves. The Company significantly increased its exploitation and development capital expenditures for 2000, spending approximately $18.0 million in the U.S., $33.5 million in South America on development/infill drilling and $1.0 million in Canada. The Company also spent approximately $6.1 million on the acquisition of seismic data and other development activities in 2000. The Company has increased its 2001 capital budget for exploitation and development work to $212 million with spending primarily aimed at U.S. and Argentina reserves.

In connection with its exploitation focus, the Company actively pursues operating cost reductions on the properties it acquires. The Company believes that its cost structure and operating practices generally result in improved operating economics. Although each situation is unique, the Company generally has achieved reductions in labor and other field level costs from those experienced by the previous operators, particularly in its acquisitions from major oil companies.

Exploitation and development activities for 2000 were concentrated mainly in Argentina and the U.S. Gulf Coast and Mid-Continent core areas of the Company. The following is a brief description of significant developments in the Company's recent exploitation and development activities:

North America. The Company's U.S. exploitation program for 2000 included the drilling of 23 gross (16.61 net) development wells, of which 21 gross (14.93 net), or 91 percent, were successful. Nine of these wells were horizontal wells drilled to the producing Edwards "A" zone on the Company's Luling field in south Texas where it has a 100 percent working interest, with eight of them being successful. These eight wells had a combined initial gross daily production buildup of 1,677 Bbls of oil (1,490 Bbls net). There are 11 additional Luling locations similar to these included in the Company's year-end 2000 reserves.

The Company's 2000 U.S. exploitation program also included 114 workovers and recompletions, of which 82 gross (76.92 net) were successful for a 72 percent success rate. The Company's Darst Creek field, in the same area as the Luling field, saw the largest amount of activity with 47 projects, generally recompletions to the deeper Edwards "A" zone from shallower zones. These recompletions resulted in a total initial daily production increase of 1,282 Bbls of oil (1,100 Bbls net). There are 221 additional similar projects booked to proved reserves in this field at year-end 2000. In addition, there are seven PUD horizontal locations to be drilled in the Darst Creek field.

The Company's 2001 exploitation budget includes $105 million targeted towards North American projects. The Company will primarily continue to focus on areas in the U.S. where it has found recent success including the Stagecoach prospect, Galveston Bay, South Pass 24 and in the Luling/Darst Creek/West Ranch areas in south Texas. Also included in the $105 million, is $10 million to be spent on the Company's newly acquired Canadian properties.

Argentina. The Company continued its highly successful development drilling program in Argentina with the drilling of 40 successful wells in 41 attempts for a 98 percent success rate. With the 1999 acquisition of the El Huemul concession and the 2000 acquisition of the Cuyo Properties, the Company's development drilling locations in Argentina have increased substantially with 212 locations being recorded in its year-end 2000 reserves.

The Company's drilling program in Argentina relies heavily on interpretation of 3-D seismic to aid in the optimum placement of wells with the acquisition of 314 square miles of 3-D seismic in 2000 and early 2001, covering portions of its Canadon Seco, Canadon Leon, Tres Picos and El Huemul concessions. With this new seismic, the Company now has a total of 567 square miles of 3-D seismic which covers 39 percent of the area of all of its concessions. The Company believes that significant additional drilling potential will continue to be identified through the acquisition of future 3-D seismic surveys. Development and extensional drilling, along with implementation of secondary recovery projects, have been the focus of the Company's historical exploitation efforts on its Argentina properties.

The Company's 2001 international exploitation budget of $107 million is heavily weighted toward projects in three of its concessions in the San Jorge Basin in Argentina: Canadon Seco, Meseta Espinosa and El Huemul. The Company is currently drilling with two rigs in its San Jorge Basin concessions and plans to add a third rig during 2001. Additionally, six horizontal oil wells in the recently acquired Piedras Colorados concession in the Cuyo Basin are planned.

The Company also plans to increase its efforts to initiate new waterfloods and optimize existing secondary recovery projects in Argentina during 2001. Only a small portion of the producing areas within the concessions controlled by the Company have been subject to secondary recovery operations. The Company believes that numerous areas currently under primary recovery will respond to waterflooding. Existing and future waterflood projects will be enhanced with the utilization of 3-D seismic as a tool to identify and high- grade specific reservoir targets.

Bolivia. Exploitation activity in Bolivia during 2001 will be focused on the Company's Naranjillos concession. Planned work includes a recompletion, stimulation of existing Devonian completions and facility modifications to increase the concession's deliverability. During 2000, the Company executed a short-term contract and a long-term contract to supply gas to affiliates of Enron South America ("Enron"). Under the terms of the short-term contract, Enron may purchase up to 14.5 MMcf of gas per day for a minimum period of six months to supply its Cuiaba integrated energy project in Brazil. Sales are anticipated to start during the second half of 2001. Under the terms of the long-term agreement, Enron may purchase up to 15.4 MMcf of gas per day contingent on its development of emerging market opportunities in Brazil and Argentina. The Company believes that it is well positioned to continue to develop markets as gas consumption continues to grow in the Southern Cone.

Ecuador. As a result of the Ecuadorian government's recent authorization of a second crude oil transportation pipeline (the "OCP"), the Company plans to increase exploitation activity in Ecuador. A 116-square-mile (300 square kilometer) 3-D seismic survey will be acquired on Block 14, Block 17 and Shiripuno concessions during the first half of 2001. A 10,100 foot development well in Block 14 targeting Cretaceous "M-1" Tena and the Napo "U" formations is planned during the first quarter of 2001. The Company anticipates an increase in its pipeline allowable (currently 6,439 gross (4,050 net) Bbls of oil per day) to accommodate production from this well. Additional infill drilling will be based on interpretation of the 3-D seismic and will be commensurate with the completion of the OCP pipeline currently estimated for the first half of 2003.

Exploration

The Company's exploration program is designed to contribute significantly to its growth. Management divides the strategic objectives of its exploration program into two parts. First, in the U.S., Canada and Argentina, the Company's exploration focus is in its core areas where its geological and engineering expertise and experience are greatest. State-of-the-art technology, including 3-D seismic, is employed to identify prospects. Exploration in the U.S., Canada and Argentina is designed to generate reserve growth in the Company's core areas in combination with its exploitation activities. The Company's longer-term plans are to increase the magnitude of this program with a goal of achieving yearly production replacement through core area exploration. Such exploration is characterized by numerous individual projects with medium to low risk. Secondly, international exploration targets significant long-term reserve growth and value creation. International exploration projects in Yemen and Ecuador are characterized by higher potential and higher risk. The Company spent approximately $81.8 million on exploration activities during 2000 (including $25.3 million on activities which are unevaluated as of December 31, 2000), spending approximately $29.5 million in Ecuador and Bolivia, $20.1 million in Yemen, $26.0 million in the United States and $6.2 million in Canada and Trinidad, adding 6.2 MMBOE to its proved reserves. A significant portion of the

Company's Yemen exploration dollars were classified as unevaluated costs at year-end 2000. The Company's 2001 exploration budget has been set at $73 million, focusing on North America drilling, principally in the U.S., and 3-D seismic acquisition in Yemen.

In conjunction with its focus on exploitation, the Company has increased its attention on growing reserves through exploration efforts as well, and while the year 2000 saw mixed results from the Company's exploration efforts, there were some positive outcomes. The following is a summary of the major exploration activities in 2000:

North America. The Company's Stagecoach prospect in western Oklahoma and its Galveston Bay and South Pass 24 areas in shallow state waters in Texas and Louisiana were the areas of focus for U.S. exploration activities in 2000. Each of these drilling programs found great success. The Company drilled nine exploratory gas wells in the Stagecoach prospect during 2000 with seven of them being successful. The Company also drilled five successful development wells in this area as offsets to previously successful exploratory wells. These 12 successful wells have total net daily production of 14,544 Mcf of gas and 213 Bbls of oil. The Company has budgeted approximately $11 million for the drilling of 19 additional exploratory wells and an additional $23 million for the drilling of 21 development wells in this area during 2001.

The Company's Galveston Bay drilling program, begun in 1997, continued to be successful in 2000 with the Company having success in five out of the six wells drilled during 2000. These gas wells in shallow state waters of Texas produce out of the Vicksburg formation from Text II sands and have a combined net daily production of 5.7 MMcf of gas and 870 Bbls of oil. The Company will continue this drilling program in 2001 with $8 million budgeted for the drilling of six wells.

The Company's South Pass 24 field located in state waters of Louisiana also produced successful gas wells in 2000, the most notable being the Tambour A-1 which has gross daily production rates of 8.6 MMcf (2.8 MMcf net) of gas and 100 Bbls (32 Bbls net) of condensate. This well, as well as the Tambour A-2, has significant behind pipe reserves. The Tambour A-2, which had an initial gross daily production rate of 5.9 MMcf (2.9 MMcf net) of gas, is currently being recompleted uphole. Two other wells were drilled by the Company in this area in 2000. Total South Pass 24 initial net daily production build-up from the four drill wells and three workovers performed in 2000 was 12.4 MMcf of gas and 180 Bbls of oil. The Company has budgeted in 2001 to continue its drilling program in South Pass 24 as well as to drill a 17,000 foot exploratory well at its Little Lake/Little Temple area of southern Louisiana.

Most recently, the Company found success in its Mills Ranch prospect in the Texas panhandle with the completion of the Mills Ranch 1-97 which is currently producing out of the Hunton formation at gross daily rates of 8.0 MMcf (1.9 MMcf net) of gas and 100 Bbls (23 Bbls net) of condensate. The Company has an offset to this well scheduled for drilling in the first half of 2001.

Bolivia. From an exploration standpoint, the Company's deep test of the Huamampampa formation and its two deep tests of the Santa Rosa formation in Bolivia also were unsuccessful. The Company did find reserves in the shallower, previously-developed Iquiri formation in two of these wells and will produce these wells from this formation when the demand for gas in Bolivia increases.

Yemen. The Company's Yemen exploration efforts consisted of three exploratory wells still in the evaluation phase and one dry hole. The An Naeem #1 found a significant gas accumulation and initially tested at a combined rate of 40 MMcf per day and 1,020 Bbls of condensate per day from two Alif zones. The An Naeem #2 was drilled down-dip from the An Naeem #1 in search of an oil rim thought to reside below the gas accumulation found in the initial well. This well also encountered gas reserves, testing at a daily rate of 27.7 MMcf of gas and 880 Bbls of condensate. The Company is currently evaluating the information obtained from these two wells to determine if an oil rim yet exists still further down-dip from the An Naeem #2. If it is so determined, the Company will drill the An Naeem #3 in a further attempt to locate the oil rim.

While the Company's Fordus well in Yemen was unsuccessful, its Harmel well found what the Company believes is a significant, previously undiscovered pool of oil which is a heavier gravity than that currently produced from this region. The Company is currently performing tests on the oil to determine if it can be commercially produced. The Company expects these tests to last into the third quarter of 2001. If the tests prove the oil to be of commercial quality, the Company will drill a second Harmel well before year end.

To aid in the evaluation of further prospects on its Yemen exploration acreage, the Company has budgeted to spend $4 million in 2001 to acquire additional 3-D seismic to fully evaluate several attractive exploration opportunities in the Alif formation that have been identified through the evaluation of existing 2-D seismic. These potential exploration targets are on trend with the neighboring Al Nasr and Dhahab fields that are currently producing oil at a combined daily rate in excess of 50,000 Bbls.

Ecuador. The Company's Rio Cotapino #1 exploration well in the Block 19 concession in Ecuador was unsuccessful. The well, drilled to a total depth of 7,060 feet, was non-productive in the Hollin and not commercially productive in the Napo "T" sand. The Company has completed all the drilling obligations associated with Block 19 and is in the process of relinquishing of the concession.

Canada. The Company's Canadian acreage acquired as part of the Cometra Acquisition in December 2000 has already produced two exploration successes for the Company. The Malmo 13-26 logged hydrocarbon pay in a Devonian reef play. Completion operations are currently underway with plans for an offset to be drilled in the second quarter of 2001. In the Milo Lake area of British Columbia, the Company has successfully discovered a new Devonian Keg River pinnacle reef field in its Milo West prospect, located approximately three miles to the west of its existing Milo Pine Point "A" pool. Based on the evidence of similar geology, the Company expects production characteristics of the Milo West discovery to be comparable to that of the Milo Pine Point "A" pool. The Pine Point "A", also a Keg River pool, discovered in 1998, is estimated to contain over 150 Bcf of gross original gas in place and currently produces at a net daily rate of 3.0 MMcf to the Company's interest (10.0 MMcf gross). Initial production from the newly discovered well at Milo West is anticipated by mid 2001. Additionally, three development wells are scheduled to be drilled in the Pine Point "A" pool during the first quarter of 2001. The Company has budgeted to spend $14 million on exploratory drilling and development activities in Canada during 2001.

Trinidad. In conjunction with the Cometra Acquisition, the Company acquired Cometra's wholly-owned subsidiary, Cometra Trinidad, Limited, which has a 36 percent working interest in approximately 28,400 gross undeveloped acreage in Trinidad. The Company is the operator of this acreage and is obligated to drill three exploratory wells on this acreage and plans to drill two of these wells, the Carapel Ridge No.1 and the Corosan No.1, in the second quarter of 2001 as Herrera sand tests.

Oil and Gas Properties

At December 31, 2000, the Company owned and operated domestic producing properties in 11 states, with its U.S. proved reserves located primarily in four core areas: the Gulf Coast, East Texas, Mid-Continent and West Coast areas. In addition, the Company established new core areas in Argentina during 1995, Bolivia during 1996, Ecuador in 1998 and Canada in 2000. As of December 31, 2000, the Company operated approximately 4,387 productive wells and also owned non-operating interests in 686 productive wells. The Company continuously evaluates the profitability of its oil, gas and related activities and has a policy of divesting itself of unprofitable leases or areas of operations that are not consistent with its operating philosophy. See "Divestiture Activities."

The following table sets forth estimates of the proved oil and gas reserves of the Company at December 31, 2000, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. ("Netherland, Sewell") for the United States, Argentina and Ecuador, as estimated by the independent petroleum consultants of DeGolyer and MacNaughton for Bolivia and as estimated by the Company for Canada:

	Oil (MBbls)			Gas (MMcf)		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total
West Coast..............	52,456	4,878	57,334	117,320	5,219	122,539
Gulf Coast..............	26,934	5,234	32,168	77,898	16,159	94,057
East Texas..............	8,076	641	8,717	80,000	13,332	93,332
Mid-Continent...........	3,308	809	4,117	58,235	30,509	88,744
Total U.S............	90,774	11,562	102,336	333,453	65,219	398,672
Argentina...............	94,191	63,345	157,536	41,822	79,377	121,199
Bolivia.................	5,668	1,157	6,825	385,623	78,236	463,859
Ecuador.................	3,915	45,560	49,475	-	-	-
Canada..................	1,558	830	2,388	33,405	6,073	39,478
Total Company........	196,106	122,454	318,560	794,303	228,905	1,023,208

Estimates of the Company's 2000 proved reserves set forth above have not been filed with, or included in reports to, any Federal authority or agency, other than the Securities and Exchange Commission.

The Company's non-producing proved reserves are largely behind-pipe in fields which it operates. Undeveloped proved reserves are predominantly development drilling locations and secondary recovery projects.

The following is a brief discussion of the Company's oil and gas operations in its core areas:

West Coast Area. The West Coast area includes oil and gas properties located primarily in Kern, Ventura and Santa Barbara Counties and the Sacramento Basin of California. The Stevens, Forbes, Grubb and Sisquoc formations are the dominant producing reservoirs on the Company's acreage in California with well depths ranging from 800 feet to 14,300 feet. As of December 31, 2000, the area comprised 16 percent of the Company's total proved reserves and 46 percent of the Company's U.S. proved reserves. The Company currently operates 1,384 productive wells and owns an interest in 166 productive wells operated by others. During 2000, net daily production for this area averaged approximately 16,200 BOE, or 40 percent of total net daily U.S. production. Numerous workovers and recompletion opportunities exist in the San Miguelito, Buena Vista and Rincon fields. Additional infill drilling locations are available in the San Miguelito and Buena Vista fields. The San Miguelito field also has waterflood potential that may add significant reserves.

Gulf Coast Area. The Gulf Coast area includes properties located in southern Texas, the southern half of Louisiana, Alabama, Mississippi and wells located in shallow state and federal waters. Production in this area is predominantly from structural accumulations in reservoirs of Miocene age. The depths of the producing reservoirs range from 1,200 feet to 14,500 feet. At December 31, 2000, the Gulf Coast area comprised approximately ten percent of the Company's total proved reserves and 28 percent of its U.S. proved reserves. The Company currently operates 818 productive wells in this area and owns an additional interest in 121 productive wells operated by others. During 2000, net daily production from this area averaged approximately 15,800 BOE, or 38 percent of total net daily U.S. production. A significant inventory of workovers and recompletions exist in eight major Gulf Coast fields from Alabama to south Texas. Development drilling potential is also available in six fields in Texas and Louisiana.

East Texas Area. The East Texas area includes properties located in the northeastern portion of Texas and the northern half of Louisiana. The Cotton Valley, Smackover, Travis Peak and Wilcox formations are the dominant producing reservoirs on the Company's acreage in this area from wells ranging in depth from 1,300 feet to 14,800 feet. The East Texas area comprised approximately five percent of the Company's December 31, 2000, total proved reserves and 15 percent of its U.S. proved reserves. The Company currently operates 546 productive wells in this area and owns an interest in an additional 106 productive wells operated by others. During 2000, net daily production for this area averaged approximately 5,500 BOE, or13 percent of total net daily U.S. production. Significant infill drilling potential exists on the Company's acreage in the South Gilmer, Southern Pine, Rosewood, Bethany Longstreet and Bear Grass fields.

Mid-Continent Area. The Mid-Continent area extends from the Arkoma Basin of eastern Oklahoma to the Texas panhandle and north to include Kansas. The Red Fork, Morrow, Skinner and Hoxbar formations are the dominant producing reservoirs on the Company's acreage in this area with well depths ranging from 1,560 feet to 17,260 feet. This area comprised four percent of the Company's December 31, 2000, total proved reserves and 11 percent of its U.S. proved reserves. The Company currently operates 258 productive wells in this area and owns an interest in an additional 193 productive wells operated by others. During 2000, net daily production for this area averaged approximately 3,600 BOE, or nine percent of total net daily U.S. production. Significant development drilling and recompletion opportunities exist in the Marlow/Velma field, plus additional projects to improve the ultimate reserve recovery exist in the Shawnee Townsite waterflood.

Argentina. The Argentina properties consist primarily of 15 mature producing concessions, 14 of which are operated by the Company, located on the south flank of the San Jorge Basin and two concessions, both operated by the Company, located in the Cuyo Basin in western Argentina. These concessions comprised approximately 36 percent of the Company's December 31, 2000, total proved reserves. During 2000, net daily production averaged approximately 25,770 Bbls of oil and 23,850 Mcf of gas. The Company currently operates 1,279 productive wells (100 percent working interest) with net daily production of 26,060 Bbls of oil and 23,800 Mcf of gas. In addition, the Company owns an interest in 22 productive wells operated by others. At December 31, 2000, the Company's proved reserves included approximately 212 development drilling locations on its Argentina acreage. In addition, the Company has an extensive inventory of workovers and development or infill drilling locations on its Argentina properties which are not included in proved reserves.

Bolivia. The Bolivia properties consist of four producing concessions and one exploration concession located in the Chaco Basin of Bolivia. The Company has 100 percent working interests in the Chaco exploration concession and the Naranjillos, Chaco Sur and Porvenir producing concessions. In the other producing concession, Nupuco, the Company has a 50 percent working interest. The Company operates all four producing concessions. These concessions comprise approximately 17 percent of the Company's December 31, 2000, total proved reserves and include 16 gross (15 net) productive wells, all of which are operated by the Company. Current net daily production is restricted by current Brazil demand to approximately 18,900 Mcf of gas and 210 Bbls of condensate. The Company is working to develop additional gas markets, both inside and outside of Bolivia, to increase the level of production from its concessions.

Ecuador. The Ecuador properties consist of two producing concessions and two exploration concessions. The Company has a 70 percent working interest in the producing Block 17 concession and a 75 percent working interest in the producing Block 14 concession. The Company also has a 100 percent interest in the Shiripuno and Block 19 exploration concessions. The Company is in the process of relinquishing its interest in Block 19. The Company currently operates 8 gross (6 net) productive wells with current gross daily production of approximately 6,350 Bbls of oil (4,075 Bbls net). These concessions comprised ten percent of the Company's December 31, 2000, total proved reserves. During the fourth quarter of 1999, the production facilities were upgraded to increase the oil storage capacity from 3,500 Bbls of oil per day to approximately 10,000 Bbls of oil per day, commensurate with the Block 14 and Block 17 development plans approved during December 1998, by the Ecuadorian government. During 1999 and 2000, one well was recompleted and high-capacity artificial lift equipment was installed on two of the producing wells to increase the combined productive capacity of the Block 14 and Block 17 concessions from 3,500 Bbls of oil per day to 6,700 Bbls of oil per day. As a result of an increase in the oil transportation allowable during 2000, these concessions are currently producing approximately 6,350 Bbls of oil per day. Additional infill drilling will be based on interpretation of the 3-D seismic and will be commensurate with the completion of the OCP pipeline currently estimated for the first half of 2003.

Canada. The Canada properties consist of 13 producing fields, principally in the provinces of Alberta and British Columbia, with additional fields in Saskatchewan and certain processing and pipeline facilities. These fields comprise approximately two percent of the Company's December 31, 2000, total proved reserves and include 156 gross (78 net) productive wells, approximately 50 percent of which are operated by the Company. Current net daily production is approximately 10 MMcf of gas and 615 Bbls of light crude oil. The Company will perform both exploitation and development activities as well as exploration activities on these properties during 2001.

Marketing

The Company's U.S. and Canada gas production and gathered gas are generally sold on the spot market or under market-sensitive, long-term agreements with a variety of purchasers, including intrastate and interstate pipelines, their marketing affiliates, independent marketing companies and other purchasers who have the ability to move the gas under firm transportation agreements. Because none of the Company's U.S. gas is committed to long-term fixed-price contracts, the Company is positioned to take advantage of the current strong gas price environment, but it is also subject to any future gas price declines. The Company's Bolivia average gas price is tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. These indexes have risen in connection with the current higher oil prices. The Company's Argentina average gas price is determined primarily by the realized oil price from the El Huemul concession.

The Company's U.S. gas marketing activities are handled by Vintage Gas, Inc., its wholly-owned gas marketing affiliate. This marketing affiliate earns fees through the marketing of Company-produced gas as well as purchases of gas on the spot market from third parties. Generally, the marketing affiliate purchases this gas on a month-to-month basis at a percentage of resale prices.

During 2000, the Company executed a short-term contract and a long-term contract to supply a portion of its Bolivia gas to affiliates of Enron South America ("Enron"). Under the terms of the short-term contract, Enron may purchase up to 14.5 MMcf of gas per day for a minimum period of six months to supply it Cuiaba integrated energy project in Brazil. Sales are anticipated to start during the second half of 2001. Under the terms of the long-term agreement, Enron may purchase up to 15.4 MMcf of gas per day contingent on its development of emerging market opportunities in Brazil and Argentina. The Company believes that it is well positioned to continue to develop markets as gas consumption continues to grow in the Southern Cone.

Generally, the Company's U.S. oil production is sold under short-term contracts at posted prices plus a premium in some cases. The Company's Argentina oil production is currently sold at port to Esso S.A.P.A., ENAP and Shell C.A.P.S.A. at West Texas Intermediate spot prices as quoted on the Platt's Crude Oil Marketwire (approximately equal to the NYMEX reference price) less a specified differential. The Company's Ecuador Block 14 and Block 17 oil production is sold to various third-party purchasers at West Texas Intermediate spot prices less a specified differential. The Company's Canadian oil production is sold under short-term contracts at posted prices. During 2000, approximately 17 percent and 12 percent of the Company's total operating revenues related to oil sales to ENAP (the Chilean government-owned oil company) and Esso S.A.P.A. (the Argentina affiliate of Exxon-Mobil), respectively.

The Company has previously engaged in oil and gas hedging activities and intends to continue to consider various hedging arrangements to realize commodity prices which it considers favorable. In 2000, the Company entered into various oil hedges (swap agreements) covering approximately 3.5 MMBbls at a weighted average price of $30.76 per Bbl (NYMEX reference price) for the calendar year 2001. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

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The following table reflects the Bbls hedged and the corresponding weighted average NYMEX reference prices by quarter:

Quarter Ending	Bbls (In Thousands)	NYMEX Reference Price Per Bbl

March 31, 2001	2,160	$ 31.48
June 30, 2001	455	30.66
September 30, 2001	460	29.61
December 31, 2001	460	28.58

Gathering Systems and Plant

The Company owns 100 percent interests in two oil and gas gathering systems located in Pottawatomie County, Oklahoma and Harris and Chambers Counties, Texas. In addition, the Company owns 100 percent interests in 18 gas gathering systems located in active producing areas of California, Kansas, Texas and Oklahoma. All of these gathering systems are operated by the Company. Together, these systems comprise approximately 263 miles of varying diameter pipe with a combined capacity in excess of 190 MMcf of gas per day. At December 31, 2000, there were 83 wells (70 wells (84 percent) which are operated by the Company) connected to these systems. Generally, the gathering systems buy gas at the wellhead on the basis of a percentage of the resale price under contracts containing terms of one to 10 years.

As part of the Nuevo Acquisition in 1999, the Company obtained ownership and operatorship of the Santa Clara Valley Gas Plant located in Ventura County, California. The plant is a 1980-vintage Randall skid-mounted cryogenic expander plant designed for 17,000 Mcf per day of inlet gas and is complete with inlet gas compression, mole sieve dehydration facilities, propane refrigeration, NGL product storage and truck loading. There are two inlet gas systems feeding the compressor units, one is a 30 pound system and the other is an 80 pound system. Sales line pressure is at 220 pounds and that pressure is obtained from the process with a turbo-expander compressor.

The plant is currently processing about 8,000 Mcf of gas per day and producing about 24,000 gallons per day of products (butane/propane). The products are trucked from the plant for sale and the approximate split is 30 percent gasoline and 70 percent butane/propane mix. Gas is purchased from various third parties, as well as the Company, primarily under wet gas purchase agreements.

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Reserves

At December 31, 2000, the Company had proved reserves of 489.1 MMBOE, comprised of 318.6 MMBbls of oil and 1.0 Tcf of gas as estimated by the independent petroleum consultants of Netherland, Sewell for the United States, Argentina and Ecuador, as estimated by the independent petroleum consultants of DeGolyer and MacNaughton for Bolivia and as estimated by the Company for Canada. For additional information on the Company's oil and gas reserves, see "Oil and Gas Properties." The following table sets forth, at December 31, 2000, the present value of future net revenues (revenues less production and development costs) before income taxes attributable to the Company's proved reserves at such date (in thousands):

Proved Reserves:	
Future net revenues..	$ 7,641,200
Present value of future net revenues before income taxes, discounted at 10 percent................................	4,338,616
Standardized measure of discounted future net cash flows...	2,951,121

Proved Developed Reserves:	
Future net revenues......................................	$ 5,852,746
Present value of future net revenues before income taxes, discounted at 10 percent................................	3,301,825

In computing this data, assumptions and estimates have been utilized, and the Company cautions against viewing this information as a forecast of future economic conditions. The historical future net revenues are determined by using estimated quantities of proved reserves and the periods in which they are expected to be developed and produced based on December 31, 2000, economic conditions. The estimated future production is priced at prices prevailing at December 31, 2000. The resulting estimated future gross revenues are reduced by estimated future costs to develop and produce the proved reserves and abandonment costs, based on December 31, 2000, cost levels, but such costs do not include debt service, general and administrative expenses and income taxes. For additional information concerning the historical discounted future net revenues to be derived from these reserves and the disclosure of the Standardized Measure information in accordance with the provisions of Statement of Financial Accounting Standards No. 69, "Disclosures about Oil and Gas Producing Activities," see Note 10 "Supplementary Financial Information for Oil and Gas Producing Activities" to the Company's consolidated financial statements included elsewhere in this Form 10-K.

The reserve data set forth in this Form 10-K represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of such estimate. Accordingly, reserve estimates often differ from the quantities of oil and gas that are ultimately recovered. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based.

For further information on reserves, costs relating to oil and gas activities and results of operations from producing activities, see Note 10 "Supplementary Financial Information for Oil and Gas Producing Activities" to the Company's consolidated financial statements included elsewhere in this Form 10-K.

Productive Wells; Developed Acreage

The following table sets forth the Company's productive wells and developed acreage assignable to such wells at December 31, 2000:

	Developed Acreage		Productive Wells			
			Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net
U.S.........................	638,202	419,625	2,705	2,375	887	452
Argentina...................	529,072	365,097	1,301	1,285	-	-
Bolivia.....................	99,458	88,339	-	-	16	15
Ecuador.....................	33,623	24,889	8	6	-	-

Canada......................	103,875	40,668	57	27	99	51
Total......................	1,404,230	938,618	4,071	3,693	1,002	518

Productive wells consist of producing wells and wells capable of production, including gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Wells which are completed in more than one producing horizon are counted as one well.

Undeveloped Acreage

At December 31, 2000, the Company held the following undeveloped acres located in the United States, Argentina, Bolivia, Ecuador, Canada, Yemen and Trinidad. With respect to such United States acreage held under leases, 208,800 gross (69,692 net) acres are held under leases with primary terms that expire at varying dates through December 31, 2004, unless commercial production is commenced. The Company has the option to relinquish portions of the undeveloped acreage in Argentina at various dates through 2007 or pay increased mining royalties. The Bolivia and Yemen acreages are held under concessions with primary terms that expire at varying dates in 2001. Of the Ecuador acreage, 494,200 acres (gross and net) relate to Block 19 which the Company is in the process of relinquishing to the government. The remainder of the Ecuador concessions have primary terms that expire at various dates in 2002 and 2006 unless there is a commercial discovery. The Canada acreage is held under leases with primary terms that expire at varying dates through 2009, unless commercial production is commenced.

State/Country	Gross Acres
California..	8,615
Colorado...	1,248
Kansas...	320
Louisiana..	2,327
North Dakota...	38,455
Oklahoma...	52,579
Texas..	109,595
Wyoming..	10,239
Total U.S..	223,378
Argentina..	832,965
Bolivia..	485,552
Ecuador..	1,276,254
Canada...	397,136
Yemen..	1,108,019
Trinidad...	28,426
Total Company..	4,351,730

Production; Unit Prices; Costs

The following table sets forth information with respect to production and average unit prices and costs for the periods indicated:

	Years Ended December 31,		
Production:	2000	1999	1998
Oil (MBbls) -			
U.S.	9,044	8,643	9,912
Argentina	9,406	7,560	6,322
Ecuador	1,261	597	78
Bolivia	131	77	122
Canada	19	-	-
Total	19,861	16,877	16,434
Gas (MMcf) -			
U.S.	35,764	39,150	42,176
Argentina	8,705	4,682	-
Bolivia	8,948	4,522	5,062
Canada	312	-	-
Total	53,729	48,354	47,238
Total MBOE	28,816	24,936	24,307
Average Sales Prices:			
Oil (per Bbl) -			
U.S.	$ 22.85(a)	$ 15.92(b)	$ 11.20
Argentina (c)	28.25	18.00	10.86
Ecuador (c)	24.27	17.28	7.34
Bolivia (c)	29.62	19.05	12.56
Canada	26.05	-	-
Total (c)	25.55(a)	16.92(b)	11.06
Gas (per Mcf) -			
U.S.	$ 3.91	$ 2.06	$ 1.97
Argentina	1.79	1.34	-
Bolivia (c)	1.75	.96	1.04
Canada	5.73	-	-
Total (c)	3.22	1.89	1.87
Production Costs (per BOE):			
U.S.	$ 6.42	$ 5.31	$ 5.57
Argentina (c)	4.87	4.30	4.67
Bolivia (c)	2.33	3.64	2.98
Ecuador (c)	4.85	3.82	4.57
Canada	7.09	-	-
Total (c)	5.54	4.88	5.23

The components of production costs may vary substantially among wells depending on the methods of recovery employed and other factors, but generally include production taxes, transportation and storage costs, maintenance and repairs, labor and utilities.

(a) Reflects the impact of oil hedges which reduced the Company's 2000

U.S. and total average oil prices per Bbl by $4.10 and $1.86, respectively.

(b) Reflects the impact of oil hedges which reduced the Company's 1999 U.S. and total average oil prices per Bbl by 11 cents and six cents, respectively.

(c) The 1999 and 1998 amounts have been restated to reflect the reclass of transportation and storage costs to lease operating costs.

Drilling Activity

During the periods indicated, the Company drilled or participated in the drilling of the following exploratory and development wells:

	YEARS ENDED DECEMBER 31,					
	2000		1999		1998	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States -						
Productive..............	21	14.93	6	1.94	34	24.94
Non-Productive..........	2	1.68	-	-	4	1.78
Argentina -	40	40.00	10	10.00	54	54.00
Productive..............	1	1.00	1	1.00	2	2.00
Non-Productive..........						
Bolivia -	-	-	1	1.00	-	-
Productive..............	-	-	-	-	-	-
Non-Productive..........	----	-----	---	-----	---	------
	64	57.61	18	13.94	94	82.72
Total.................	====	=====	===	=====	===	======
Exploratory:						
United States -						
Productive..............	14	6.17	1	0.47	22	15.17
Non-Productive..........	4	2.02	11	5.56	13	3.78
Argentina -						
Productive..............	-	-	-	-	2	2.00
Non-Productive..........	-	-	-	-	-	-
Bolivia						
Productive..............	-	-	7	7.00	1	1.00
Non-Productive..........	3	3.00	-	-	-	-
Ecuador -						
Productive..............	-	-	-	-	-	-
Non-Productive..........	1	1.00	-	-	-	-
Canada -						
Productive..............	-	-	-	-	-	-
Non-Productive..........	1	0.45	-	-	-	-

Yemen -						
Productive..............	-	-	-	-	-	-
Non-Productive..........	1	0.75	-	-	-	-
	24	13.39	19	13.03	38	21.95
Total:						
Productive..............	75	61.10	25	20.41	113	97.11
Non-Productive..........	13	9.90	12	6.56	19	7.56
Total.................	88	71.00	37	26.97	132	104.67

The above well information excludes wells in which the Company has only a royalty interest.

At December 31, 2000, the Company was a participant in the drilling, completion or evaluation of 22 gross (19.45 net) wells. All of the Company's drilling activities are conducted with independent contractors. The Company owns no drilling equipment.

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Seasonality

The results of operations of the Company are somewhat seasonal due to seasonal fluctuations in the price for gas. Gas prices have been generally higher in the fourth and first quarters. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of results which may be realized on an annual basis.

Competition

Competition in the oil and gas industry is intense. Both in seeking to acquire desirable producing properties, new leases and exploration prospects and in marketing oil and gas, the Company faces competition from both major and independent oil and gas companies, as well as from numerous individuals and drilling programs. Many of these competitors have financial and other resources substantially in excess of those available to the Company. Alternative fuel sources, including heating oil and other fossil fuels, also present competition.

Exploration for and production of oil and gas are affected by the availability of pipe, casing and other tubular goods and certain other oil field equipment, including drilling rigs and tools. The Company is dependent upon independent drilling contractors to furnish rigs, equipment and tools to drill the wells it operates. The Company has not experienced and does not anticipate difficulty in obtaining supplies, materials, equipment or tools. Higher prices for oil and gas production, however, may cause competition for these items as well as drilling and workover rigs in particular to increase, and may result in increased costs of operations and impact the timing of planned projects.

Regulation

The domestic oil and gas industry is extensively regulated by federal, state and local authorities. Legislation affecting the oil and gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, have issued rules and regulations affecting the oil and gas industry and its individual members, some of which carry substantial penalties for the failure to comply. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. Inasmuch as such laws and regulations are frequently amended or reinterpreted, the Company is unable to predict the future cost or impact of complying with such regulations.

Exploration and Production. Exploration and production operations of the Company are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandoning of wells. The Company's operations are also subject to various conservation regulations, including regulation of the size of drilling and spacing units or proration units, the density of wells which may be drilled and the unitization or pooling of oil and gas properties. In this regard, some states allow the forced pooling or integration of lands and leases to facilitate exploration, while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum, quarterly and/or daily allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and gas the Company can produce from its wells and the number of wells or the locations at which the Company can drill.

Various federal, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect exploration, development and production operations of the Company. For example, the discharge or substantial threat of a discharge of oil by the Company into United States waters or onto an adjoining shoreline may subject the Company to liability under the Oil Pollution Act of 1990 and similar state laws. While liability under the Oil Pollution Act of 1990 is limited under certain circumstances, such limits are so high that the maximum liability would likely have a significant adverse effect on the Company. The Company's operations generally will be covered by insurance which the Company believes is adequate for these purposes. However, there can be no assurance that such insurance coverage will always be in force or that, if in force, it will adequately cover any losses or liability the Company may incur. The Company is also subject to laws and regulations concerning occupational safety and health. It is not anticipated that the Company will be required in the near future to expend any amounts that are material in the aggregate to the Company's overall operations by reason of environmental or occupational safety and health laws and regulations, but because such laws and regulations are frequently changed, the Company is unable to predict the ultimate cost of compliance.

Certain of the Company's oil and gas leases are granted by the federal government and administered by various federal agencies. Such leases require compliance with detailed federal regulations and orders which regulate, among other matters, drilling and operations on these leases and calculation of royalty payments to the federal government. The Mineral Lands Leasing Act of 1920 places limitations on the number of acres under federal leases that may be owned in any one state. While subject to this law, the Company does not have a substantial federal lease acreage position in any state or in the aggregate. The Mineral Lands Leasing Act of 1920 and related regulations also may restrict a corporation from the holding of a federal onshore oil and gas lease if stock of such corporation is owned by citizens of foreign countries which are not deemed reciprocal under such Act. Reciprocity depends, in large part, on whether the laws of the foreign jurisdiction discriminate against a United States person's ownership of rights to minerals in such jurisdiction. The purchase of such shares in the Company by citizens of foreign countries who are not deemed to be reciprocal under such Act could have an impact on the Company's ownership of federal leases.

Marketing, Gathering and Transportation. Federal legislation and regulatory controls have historically affected the price of the gas produced and sold by the Company and the manner in which such production is marketed. Historically, the transportation and sale for resale of gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the "NGA"), the Natural Gas Policy Act of 1978 (the "NGPA") and the regulations promulgated thereunder by the Federal Energy Regulatory Commission ("FERC"). The Natural Gas Wellhead Decontrol Act of 1989 amended the NGPA to remove as of January 1, 1993, the remaining natural gas wellhead pricing, sales, certificate and abandonment regulation of first sales that had been regulated by the FERC.

Commencing in 1985, the FERC through Order Nos. 436, 500, 636 and 637 promulgated changes that significantly affect the transportation and marketing of gas. These changes have been intended to foster competition in the gas industry by, among other things, inducing or mandating that interstate pipeline companies provide nondiscriminatory transportation services to producers, distributors, buyers and sellers of gas and other shippers (so-called "open access" requirements). The FERC has also sought to expedite the certification process for new services, facilities, and operations of those pipeline companies providing "open access" services.

In 1992, the FERC issued Order 636. Among other things, Order 636 required each interstate pipeline company to "unbundle" its traditional wholesale services and create and make available on an open and nondiscriminatory basis numerous constituent services (such as gathering services, storage services, firm and interruptible transportation services, and stand-by sales services) and to adopt a new rate making methodology to determine appropriate rates for those services. Each pipeline company had to develop the specific terms of service in individual proceedings. Some of the individual pipeline company restructurings are still the subject of appeals and resulting remand proceedings concerning certain issues. Although the regulations do not directly regulate gas producers such as the Company, the availability of non-discriminatory transportation services and the ability of pipeline customers to modify or terminate their existing purchase obligations under these regulations have greatly enhanced the ability of producers to market their gas directly to end users and local distribution companies. In this regard, access to markets through interstate gas pipelines is critical to the marketing activities of the Company.

In 2000, the FERC issued Order 637 in order to make short-term capacity release more viable and to foster the market becoming more competitive and transparent and prices more efficient. Among other things, Order 637 removes the price cap on short-term capacity releases, allows peak/offpeak rates for short-term services to better reflect seasonal market demands and permits pipelines to propose term-differentiated rates to better reflect the underlying contracting risks of both pipelines and shippers.

The FERC has issued a new policy regarding the use of nontraditional methods of setting rates for interstate gas pipelines in certain circumstances as alternatives to cost-of-service based rates. A number of pipelines have obtained FERC authorization to charge negotiated rates as one such alternative.

Under the NGA, gas gathering facilities are generally exempt from FERC jurisdiction. Interstate transmission facilities are, on the other hand, subject to FERC jurisdiction. The FERC has historically distinguished between these types of activities on a very fact-specific basis which makes it difficult to predict with certainty the status of the Company's gathering facilities. While the FERC has not issued any order or opinion declaring the Company's facilities as gathering rather than transmission facilities, the Company believes that these systems meet the traditional tests that the FERC has used to establish a pipeline's status as a gatherer. As a result of FERC's allowing a number of interstate pipelines to spin-off gathering systems and thereby exempt them from Federal regulation, states are now enacting or considering statutory and/or regulatory provisions to regulate gathering systems. The Company's gathering systems could be adversely affected should they be subjected in the future to the application of such state regulation.

With respect to oil pipeline rates subject to the FERC's jurisdiction, in October 1993 the FERC issued Order 561 to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992. Order 561 established an indexing system, effective January 1, 1995, under which most oil pipelines will be able to readily change their rates to track changes in the Producer Price Index for Finished Goods (PPI-FG), minus one percent. This index established ceiling levels for rates. Order 561 also permits cost-of-service proceedings to establish just and reasonable rates. The order does not alter the right of a pipeline to seek FERC authorization to charge market-based rates. However, until the FERC makes the finding that the pipeline does not exercise significant market power, the pipeline's rates cannot exceed the applicable index ceiling level or a level justified by the pipeline's cost of service.

The Company's operations in Argentina, Bolivia, Ecuador, Canada and Yemen are subject to various laws and regulations in those countries. These laws and regulations as currently imposed are not anticipated to have a material adverse effect upon the Company's operations. The Company's Bolivian projects are dependent, in part, on the continued market development of the Bolivia-to-Brazil gas pipeline.

Employees

The Company employs approximately 239 full-time people in its Tulsa office whose functions are associated with management, engineering, geology, land and legal, accounting, financial planning, and administration. In addition, approximately 188 full-time employees are responsible for the supervision and operation of its U.S. field activities. The Company also has approximately 271 employees for the management and operation of its properties in Argentina, Bolivia, Ecuador, Canada and Yemen. The Company believes its relations with its employees are excellent.

Item 3. Legal Proceedings.

The Company is a named defendant in lawsuits and is a party in governmental proceedings from time to time arising in the ordinary course of business. While the outcome of such lawsuits or proceedings against the Company cannot be predicted with certainty, management does not expect these matters to have a material adverse effect on the Company's financial position or results of operations.

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

There were no matters submitted to the Company's stockholders during the fourth quarter of the fiscal year ended December 31, 2000.

Item 4A. Executive Officers of the Registrant.

The following table sets forth as of the date hereof certain information regarding the executive officers of the Company. Officers are elected annually by the Board of Directors and serve at its discretion.

NAME	AGE	POSITION
Charles C. Stephenson, Jr.........	64	Director and Chairman of the Board of Directors
S. Craig George...................	48	Director, President and Chief Executive Officer
William L. Abernathy..............	49	Director, Executive Vice President and Chief Ope
William C. Barnes.................	46	Director, Executive Vice President, Chief Financ Secretary and Treasurer
William E. Dozier.................	48	Senior Vice President - Operations
Robert W. Cox.....................	55	Vice President - General Counsel
Andy R. Lowe......................	49	Vice President - Marketing
Michael F. Meimerstorf............	44	Vice President and Controller
Robert E. Phaneuf.................	54	Vice President - Corporate Development
Larry W. Sheppard.................	46	Vice President - International
Martin L. Thalken.................	40	Vice President - Acquisitions

Mr. Stephenson, a co-founder of the Company, has been a Director since June 1983 and Chairman of the Board of Directors of the Company since April 1987. He was also Chief Executive Officer of the Company from April 1987 to March 1994 and President of the Company from June 1983 to May 1990. From October 1974 to March 1983, he was President of Santa Fe-Andover Oil Company (formerly Andover Oil Company), an independent oil and gas company ("Andover"), and from January 1973 to October 1974, he was Vice President of Andover. Mr. Stephenson has a B.S. Degree in Petroleum Engineering from the University of Oklahoma, and has approximately 41 years of oil and gas experience.

Mr. George has been a Director since October 1991, President of the Company since September 1995 and Chief Executive Officer of the Company since December 1997. He was also Chief Operating Officer of the Company from March 1994 to December 1997, an Executive Vice President of the Company from March 1994 to September 1995 and a Senior Vice President of the Company from October 1991 to March 1994. From April 1991 to October 1991, Mr. George was Vice President of Operations and International with Santa Fe Minerals, Inc., an independent oil and gas company ("Santa Fe Minerals"). From May 1981 to March 1991, he served in various other management and executive capacities with Santa Fe Minerals and its subsidiary, Andover. From December 1974 to April 1981, Mr. George held various management and engineering positions with Amoco Production Company. He has a B.S. Degree in Mechanical Engineering from the University of Missouri-Rolla.

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Mr. Abernathy has been a Director since October 1999, and an Executive Vice President and Chief Operating Officer of the Company since December 1997. He was Senior Vice President--Acquisitions of the Company from March 1994 to December 1997, Vice President--Acquisitions of the Company from May 1990 to March 1994 and Manager--Acquisitions of the Company from June 1987 to May 1990. From June 1976 to June 1987, Mr. Abernathy was employed by Exxon Company USA, where he served at various times as Senior Staff Engineer, Senior Supervising Engineer and in other engineering capacities, with assignments in drilling, production and reservoir engineering in the Gulf Coast and offshore. He has B.S. and M.S. Degrees in Mechanical Engineering from Auburn University.

Mr. Barnes, a certified public accountant, has been a Director, Treasurer and Secretary of the Company since April 1987, an Executive Vice President of the Company since March 1994 and Chief Financial Officer of the Company since May 1990. He was also a Senior Vice President of the Company from May 1990 to March 1994 and Vice President--Finance of the Company from January 1984 to May 1990. From November 1982 to December 1983, Mr. Barnes was an audit manager for Arthur Andersen & Co., an independent public accounting firm, where he dealt primarily with clients in the oil and gas industry. He was Assistant Controller --Finance of Andover from December 1980 to November 1982. From June 1976 to December 1980, he was an auditor with Arthur Andersen & Co., where he dealt primarily with clients in the oil and gas industry. Mr. Barnes has a B.S. Degree in Business Administration from Oklahoma State University.

Mr. Dozier has been Senior Vice President--Operations of the Company since December 1997. From May 1992 to December 1997, he was Vice President--Operations of the Company. From June 1983 to April 1992, he was employed by Santa Fe Minerals where he held various engineering and management positions serving most recently as Manager of Operations Engineering. From January 1975 to May 1983, he was employed by Amoco Production Company serving in various positions where he worked all phases of production, reservoir evaluations, drilling and completions in the Mid-Continent and Gulf Coast areas. He has a B.S. Degree in Petroleum Engineering from the University of Texas.

Mr. Cox has been Vice President--General Counsel of the Company since March 1988. From August 1982 to March 1988, he was employed by Santa Fe Minerals and its subsidiary, Andover, where he served at various times as Vice President--Law and Regional Attorney. From April 1982 to August 1982, he was employed as Corporate Attorney by Andover. Prior to that time, Mr. Cox was employed by Amerada Hess Corporation, a major oil company, served as General Counsel and Secretary of Kissinger Petroleum Corporation, an independent oil and gas company, and served on the legal staff of Champlin Petroleum Company, an independent oil and gas company. He has a B.S. Degree in Business Administration with a major in Petroleum Marketing from the University of Tulsa, and a Juris Doctor from the University of Michigan Law School.

Mr. Lowe has been Vice President--Marketing of the Company since December 1997. He was General Manager--Marketing of the Company from July 1992 to December 1997. From September 1983 to November 1990, he was employed by Maxus Energy Corporation, formerly Diamond Shamrock Exploration Company, serving as Manager--Marketing and in various other management and supervisory capacities. From 1981 to September 1983, he was employed by American Quasar Exploration Company as Manager--Oil and Gas Marketing. From 1978 to 1981, he was employed by Texas Pacific Oil Company serving in various positions in production and marketing. He has a B.S. Degree in Education from Texas Tech University.

Mr. Meimerstorf, a certified public accountant, has been Controller of the Company since January 1988 and a Vice President of the Company since May 1990. He was Accounting Manager of the Company from February 1984 to January 1988. From April 1981 to February 1984, he was the Financial Reporting Supervisor for Andover. From June 1979 to April 1981, he was an auditor with Arthur Andersen & Co. He has a B.S. Degree in Accounting from Arkansas Tech University and an M.B.A. Degree from the University of Arkansas.

Mr. Phaneuf has been Vice President--Corporate Development of the Company since October 1995. From June 1995 to October 1995, he was employed in the Corporate Finance Group of Arthur Andersen LLP, specializing in energy industry corporate finance activities. From April 1993 to August 1994, he was Senior Vice President and head of the Energy Research Group at Kemper Securities, an investment banking firm. From 1988 until April 1993, he was employed by

Rauscher, Pierce Refsnes, Inc., an investment banking firm, as a Senior Vice President, serving as an energy analyst involved in equity research. From 1978 to 1988, Mr. Phaneuf was Vice President of Kidder, Peabody, & Co., an investment banking firm, serving as an energy analyst in the Research Department. From 1976 to 1978, he was employed by Schneider, Bernet, and Hickman, serving as an energy analyst in the Research Department. From 1972 to 1976, he held the position of Investment Advisor for First International Investment Management, a subsidiary of NationsBank. He holds a B.A. Degree in Psychology and an M.B.A. Degree from the University of Texas.

Mr. Sheppard has been Vice President--International of the Company since November 1994. From June 1984 to August 1994, he was employed by Santa Fe Minerals serving as Manager--Acquisitions & Special Projects, Manager--International Operations, and in various other management and supervisory capacities. From August 1977 to June 1984, he was employed by Amoco Production Company serving in various engineering and supervisory capacities. He has a B.S. Degree in Petroleum Engineering from Texas Tech University.

Mr. Thalken has been Vice President--Acquisitions of the Company since December 1997. He was Acquisitions Technical Manager of the Company from May 1995 to December 1997 and an acquisitions engineer with the Company from January 1992 to May 1995. From October 1990 to December 1991, he was employed by Enron Oil and Gas Company, serving as a production engineer. From May 1983 to September 1990, he was employed by Exxon Company, USA, in various engineering and supervisory capacities. He has a B.S. Degree in Mechanical Engineering from the University of Kansas.

PART II

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

The Company's common stock commenced trading on the New York Stock Exchange on August 3, 1990, under the symbol "VPI." The following table sets forth the high and low sale prices per share of the Company's common stock, as reported in the New York Stock Exchange composite transactions, and the cash dividends paid per share of common stock, for the periods indicated:

	High	Low	Dividends Paid
2000			
First Quarter..............	$20.5625	$11.1875	$.025
Second Quarter.............	25.1250	18.1250	.025
Third Quarter..............	24.7500	16.8125	.03
Fourth Quarter.............	27.9375	18.1250	.03
1999			
First Quarter..............	$10.0625	$ 4.0625	$.025
Second Quarter.............	12.2500	8.1250	-
Third Quarter..............	15.1250	10.1250	-
Fourth Quarter.............	13.7500	9.0625	-

Substantially all of the Company's stockholders maintain their shares in "street name" accounts and are not, individually, stockholders of record. As of December 31, 2000, the common stock was held by 107 holders of record and approximately 10,000 beneficial owners.

The Company began paying a quarterly cash dividend in the fourth quarter of 1992 and continued paying a regular quarterly cash dividend through the first quarter of 1999. Due to the historically low oil and gas price environment during the first quarter of 1999, the Company suspended its regular quarterly cash dividend for the remainder of 1999. The Company re-instituted the payment of dividends beginning in the first quarter of 2000 with a $.025 per share cash dividend paid on February 3, 2000, to stockholders of record on January 25, 2000, and expects to continue paying a regular quarterly cash dividend. However, subject to restrictions under credit arrangements, the determination of the amount of future cash dividends, if any, to be declared and paid, will depend upon, among other things, the Company's financial condition, funds from operations, the level of its capital expenditures and its future business prospects. The Company's credit arrangements (including the indentures for its outstanding senior subordinated indebtedness) contain certain restrictions on the payment of cash dividends, the most restrictive of which prohibits the payment of cash dividends if such payments would reduce Net Worth (as defined in the Company's revolving credit facility) below the sum of $375 million plus 75 percent of net proceeds of any future equity offerings less any impairment writedowns required by GAAP or by the Securities and Exchange Commission and excluding any impact related to SFAS No. 133. Net Worth was approximately $613 million at December 31, 2000.

Item 6. Selected Financial Data.

SELECTED FINANCIAL AND OPERATING DATA

	Years Ended Decem		
	2000	1999	1998
	(In thousands, except per share am		
Income Statement Data:			
Oil and gas sales (a)	$ 680,350	$ 376,924	$ 270,251
Gas marketing revenues	128,836	60,275	54,108
Gathering revenues	19,998	6,955	7,741
Total revenues (a)	806,181	502,928	333,323
Operating expenses (a)	300,477	184,367	184,932
Exploration costs	25,242	14,674	24,056
Impairment of oil and gas properties	225	3,306	70,913
Depreciation, depletion and amortization	100,109	107,807	108,975
Interest	48,437	58,665	43,680
Net income (loss)	195,893	73,371	(87,665
Income (loss) per share before cumulative effect of change in accounting principle:			
Basic	3.15	1.27	(1.69
Diluted	3.08	1.24	(1.69
Income (loss) per share:			
Basic	3.13	1.27	(1.69
Diluted	3.06	1.24	(1.69
Dividends declared per share	.14	-	.09
Balance Sheet Data (end of year):			
Total assets	$1,338,397	$1,168,134	$1,014,175
Long-term debt, less current portion	464,229	625,318	672,507

Stockholders' equity	624,857	431,129	273,958
Operating Data:			
Production:			
Oil (MBbls)	19,861	16,877	16,434
Gas (MMcf)	53,729	48,354	47,238
Average Sales Prices:			
Oil (per Bbl)	$ 25.55	$ 16.92	$ 11.06
Gas (per Mcf)	3.22	1.89	1.87
Proved Reserves (end of year):			
Oil (MBbls)	318,560	303,190	164,457
Gas (MMcf)	1,023,208	988,989	806,833
Total proved reserves (MBOE)	489,095	468,022	298,929
Present value of estimated future net revenues before income taxes discounted at 10 percent (in thousands):			
Oil and gas properties	$4,338,616	$2,989,626	$ 703,211
Gathering systems and plant	14,188	13,764	4,493
Standardized measure of discounted future net cash flows (in thousands)	2,951,121	2,247,237	648,222

Significant acquisitions of producing oil and gas properties during 1999, 1997 and 1995 and significant dispositions of oil and gas properties during 1999 affect the comparability between the Financial and Operating Data for the years presented above.

(a) These amounts have been restated to reflect the reclass of transportation and storage costs to lease operating costs.

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

Results of Operations

The Company's results of operations have been significantly affected by its success in acquiring oil and gas properties and its ability to maintain or increase production through its exploitation and exploration activities. Fluctuations in oil and gas prices have also significantly affected the Company's results. The following table reflects the Company's oil and gas production and its average oil and gas prices for the periods presented:

	Years Ended December 31,		
	2000	1999	1998
Production:			
Oil (MBbls) -			
U.S.	9,044	8,643	9,912
Argentina	9,406	7,560	6,322
Ecuador	1,261	597	78
Bolivia	131	77	122
Canada	19	-	-

Total................	19,861(a)	16,877	16,434
Gas (MMcf) -			
U.S....................	35,764	39,150	42,176
Argentina..............	8,705	4,682	-
Bolivia................	8,948	4,522	5,062
Canada.................	312	-	-
Total................	53,729	48,354	47,238
Total MBOE.................	28,816	24,936	24,307
Average Sales Prices:			
Oil (per Bbl) -			
U.S....................	$ 22.85(b)	$ 15.92(c)	$ 11.20
Argentina..............	28.25	18.00	10.86
Ecuador................	24.27	17.28	7.34
Bolivia................	29.62	19.05	12.56
Canada.................	26.05	-	-
Total................	25.55(b)	16.92(c)	11.06
Gas (per Mcf) -			
U.S....................	$ 3.91	$ 2.06	$ 1.97
Argentina..............	1.79	1.34	-
Bolivia................	1.75	.96	1.04
Canada.................	5.73	-	-
Total................	3.22	1.89	1.87

(a) Total production for the year, before the impact of changes in inventories (accounted for as a result of the mandated change in accounting principle), was 19,921 MBbls (Argentina-9,512 MBbls, Ecuador-1,227 MBbls, Bolivia-119 MBbls).

(b) Reflects the impact of oil hedges which reduced the Company's 2000 U.S. and total average oil prices per Bbl by $4.10 and $1.86, respectively.

(c) Reflects the impact of oil hedges which reduced the Company's 1999 U.S. and total average oil prices per Bbl by 11 cents and six cents, respectively.

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Average U.S. oil prices received by the Company fluctuate generally with changes in the NYMEX reference price for oil. The Company's Argentina oil production is sold at West Texas Intermediate spot prices as quoted on the Platt's Crude Oil Marketwire (approximately equal to the NYMEX reference price) less a specified differential. Production from the Company's Block 14 and Block 17 in Ecuador is sold to various third party purchases at West Texas Intermediate spot prices less a specified differential. The Company experienced a 53 percent increase in its average oil price in 1999 compared to 1998 as a result of OPEC's efforts to reduce the available supply of crude oil in the global markets along with increasing demand. This increase continued in 2000 with the Company experiencing a gain of 51 percent in its average oil price over the 1999 average oil price. The Company participated in oil hedges covering 9.3 MMBbls and 1.84 MMBbls during 2000 and 1999, respectively. The impact of these hedges reduced the Company's U.S. average oil price for 2000 and 1999 by $4.10 and 11 cents to $22.85 and $15.92 per Bbl, respectively, and its overall average oil price by $1.86 and six cents to $25.55 and $16.92 per Bbl, respectively. The Company was not a party to any oil hedges in 1998.

The Company's realized average oil price for 2000 (before hedges) was approximately 91 percent of the NYMEX reference price compared to 88 percent in 1999 and 77 percent in 1998.

Average U.S. gas prices received by the Company fluctuate generally with changes in spot market prices, which may vary significantly by region. The Company's Bolivia average gas price is tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. During 2000 and the last half of 1999, these fuel oil indexes increased in conjunction with the current higher oil price environment. In Argentina, the Company's average gas price is primarily determined by the realized price of oil from its El Huemul concession, however, this contract expires at the end of 2001. The Company anticipates securing long-term contracts for this gas during 2001 and it expects future gas prices to be at lower levels than the current contract. The Company's Canada gas is generally sold at spot market prices as reflected by the AECO gas price index. The Company's total average gas price for 2000 was 70 percent higher than 1999's and 1999 was one percent higher than 1998's.

The Company has previously engaged in oil and gas hedging activities and intends to continue to consider various hedging arrangements to realize commodity prices which it considers favorable. The Company has entered into various oil hedges (swap agreements) for a total of 3.5 MMBbls of oil at a weighted average price of $30.76 per Bbl (NYMEX reference price) for calendar year 2001. For additional information, see "Business and Properties - Marketing" included elsewhere in this Form 10-K. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

Relatively modest changes in either oil or gas prices significantly impact the Company's results of operations and cash flow. However, the impact of changes in the market prices for oil and gas on the Company's average realized prices may be reduced from time to time based on the level of the Company's hedging activities. Based on 2000 oil production, a change in the average oil price realized, before hedges, by the Company of $1.00 per Bbl would result in a change in net income and cash flow before income taxes on an annual basis of approximately $12.7 million and $19.4 million, respectively. A 10 cent per Mcf change in the average price realized, before hedges, by the Company for gas would result in a change in net income and cash flow before income taxes on an annual basis of approximately $3.3 million and $5.3 million, respectively, based on 2000 gas production.

Period to Period Comparison

Year Ended December 31, 2000, Compared to Year Ended December 31, 1999

The Company reported net income of $195.9 million for the year ended December 31, 2000, compared to net income of $73.4 million for the same period in 1999. A 51 percent increase in average oil prices and a 70 percent increase in average gas prices received by the Company and a 16 percent increase in production on a BOE basis were primarily responsible for the significant increase in its net income.

Oil and gas sales increased $303.5 million (81 percent), to $680.4 million for 2000 from $376.9 million for 1999. A 51 percent increase in average oil prices combined with an 18 percent increase in oil production accounted for an increase of $221.9 million. A 70 percent increase in average gas prices, coupled with an 11 percent increase in gas production, accounted for an additional increase of $81.6 million. The Company had an 18 percent increase in oil production primarily as a result of Argentina production added through the 1999 acquisitions of the El Huemul concession (the "El Huemul Acquisition") and additional working interests in its two producing concessions in Ecuador (collectively, the "1999 Acquisitions") and the exploitation activities in Argentina. The Company's gas production rose by 11 percent due primarily to the gas production from the El Huemul concession acquired in July 1999 and increased production in Bolivia as a result of increased takes into the Bolivia-to-Brazil pipeline. This increase more than offset the decline in U.S. gas production as a result of the December 1999 sale of certain oil and gas properties located in northern California's Sacramento Basin area.

Gains on disposition of assets of $55.0 million ($33.6 million net of income taxes) were reflected in 1999 as a result of $87.9 million in proceeds from various oil and gas property divestitures in the United States. Other than the $55.0 million in gains reported, the divestitures did not have a significant impact on the Company's 1999 results of operations as the majority of the divestitures occurred during December 1999. In 2000, the Company recorded a loss on the disposition of assets, primarily as a result of post-closing adjustments on 1999 dispositions, of $1.7 million.

As a result of an unfavorable decision by the Supreme Court of Argentina, the Company recorded as other expense in 2000 a non-recurring charge of $25.1 million ($16.3 million net of tax). No similar charge existed in 1999. For further information regarding this litigation see Note 4 "Commitments and Contingencies" to the consolidated financial statements included elsewhere in this Form 10-K.

Lease operating expenses, including production taxes, increased $37.9 million (31 percent), to $159.6 million for 2000 from $121.7 million for 1999. The increase in lease operating expenses is due primarily the 1999 Acquisitions and an increase in production taxes due to higher product prices. Lease operating expenses per equivalent barrel produced increased to $5.54 in 2000 from $4.88 for the same period in 1999. As the result of a Securities and Exchange Commission mandate, transportation and storage costs billed to the Company have been reclassified to lease operating expenses for all periods shown. These costs had been previously reported as a reduction of oil and gas revenues consistent with oil and gas industry practice. This reclassification added $0.25 and $0.40 to the reported lease operating expense per BOE for the years 1999 and 2000, respectively.

Exploration costs increased $10.5 million (71 percent), to $25.2 million for 2000 from $14.7 million for 1999. During 2000, the Company's exploration costs included $24.5 million for unsuccessful exploratory drilling and leasehold impairments associated with a much higher exploration capital budget and the drilling of an increased number of higher-risk exploratory wells during the year, and $0.7 million for seismic and other geological and geophysical costs. Due to reduced cash flow levels, the Company significantly reduced its capital budget for 1999. Exploration expenses for 1999 consisted of $5.1 million for seismic data acquisition, $4.4 million for unsuccessful exploratory drilling and $5.2 million for lease impairments and other geological and geophysical costs.

General and administrative expenses increased $5.0 million (14 percent), to $41.4 million for 2000 from $36.4 million for 1999, due primarily to personnel additions in conjunction with increased capital expenditures, the 1999 Acquisitions and the delay of 1999 annual compensation adjustments from January until August. The Company's G&A per BOE for 2000 was $1.44 compared to $1.46 for 1999.

Depreciation, depletion and amortization decreased $7.7 million (7 percent), to $100.1 million for 2000 from $107.8 million for 1999, despite a 16 percent increase in total production due primarily to higher reserves resulting from higher product prices used throughout the year in the DD&A calculation.

The Company's average DD&A rate per equivalent barrel produced decreased from $4.15 in 1999 to $3.33 in 2000.

Interest expense decreased $10.3 million (17 percent), to $48.4 million for 2000 from $58.7 million for 1999, due primarily to a 25 percent decrease in the Company's total average outstanding debt due to the Company's significant repayment of outstanding debt as a result of significantly increased cash flow and the $87.9 million of cash proceeds from the sale of oil and gas properties in late 1999. The Company's average interest rate for its outstanding debt for 2000 was 8.87 percent compared to 8.14 percent in 1999.

Year Ended December 31, 1999, Compared to Year Ended December 31, 1998

The Company reported net income of $73.4 million for the year ended December 31, 1999, compared to a net loss of $87.7 million for the same period in 1998. A 53 percent increase in average oil prices received by the Company was primarily responsible for the significant increase in its net income. The Company also recorded after-tax gains on property sales of $33.6 million in 1999. The Company's net loss recorded in 1998 was primarily the result of historically low oil prices which greatly reduced revenues and led to an oil and gas property impairment of $70.9 million ($43.2 million net of tax).

Oil and gas sales increased $106.6 million (39 percent), to $376.9 million for 1999 from $270.3 million for 1998. A 53 percent increase in average oil prices combined with a three percent increase in oil production, accounted for an increase of $103.7 million. A one percent increase in average gas prices, coupled with a two percent increase in gas production, accounted for an additional increase of $2.9 million. The Company experienced a three percent increase in oil production primarily as a result of Argentina production added through the El Huemul Acquisition which offset the decline in the Company's U.S. oil production primarily due to the shutting in of certain high cost properties during the first half of 1999 as a result of historically low oil prices. The Company's gas production rose by two percent due to the gas production attributable to the El Huemul concession acquired in July 1999 which more than offset the decrease in U.S. gas production resulting from the natural decline in the Galveston Bay field and the decrease in Bolivia production due to limited gas demand from the developing export market in Brazil.

Gains on disposition of assets of $55.0 million ($33.6 million net of income taxes) were reflected in 1999 as a result of $87.9 million in proceeds from various oil and gas property divestitures in the United States. Other than the $55.0 million in gains reported, the divestitures did not have a significant impact on the Company's results of operations as the majority of the divestitures occurred during December 1999. The Company also does not expect a significant impact on its continuing operations due to these divestitures as interest savings from the reduction in debt are expected to generally offset any future reduction in earnings.

Lease operating expenses, including production taxes, decreased $5.4 million (4 percent), to $121.7 million for 1999 from $127.1 million for 1998. The decrease in lease operating expenses, despite the three percent increase in production, is due primarily to actions taken by the Company to reduce costs including shutting in certain high cost properties, rebidding field service and product contracts and the reorganization of certain field operations. Lease operating expenses per equivalent barrel produced decreased to $4.88 in 1999 from $5.23 for the same period in 1998.

Exploration costs decreased $9.4 million (39 percent), to $14.7 million for 1999 from $24.1 million for 1998. During 1998, the Company's exploration costs included $13.9 million for the acquisition of 3-D seismic data primarily in the U.S. Gulf Coast area and Bolivia, $4.8 million for unsuccessful exploratory drilling, and $5.4 million for lease impairments and other geological and geophysical costs. Due to reduced cash flow levels, the Company significantly reduced its capital budget for 1999. As a result, exploration expenses for 1999 consisted of only $5.3 million for seismic data acquisition, $4.4 million for unsuccessful exploratory drilling and $5.0 million for lease impairments and other geological and geophysical costs.

Impairments of oil and gas properties of $3.3 million were recognized in 1999, compared to $70.9 million of impairments in 1998, which resulted primarily from the decline in oil prices which took place in the last quarter of 1998. The impairments recorded in 1999 were primarily as a result of mechanical failures which were uneconomic to repair and unsuccessful development projects on various fields in the United States. The Company reviews its proved properties for impairment on a field basis and recognizes an impairment whenever events or circumstances (such as declining oil and gas prices or unsuccessful development projects) indicate that the properties' carrying value may not be recoverable. If an impairment is indicated based on the Company's estimated future net revenues for total proved reserves on a field basis, then a provision is recognized to the extent that the carrying value exceeds the present value of the estimated future net revenues (fair value). In estimating the future net revenues, the Company assumed that the current oil price environment would return to more historical levels over a short period of time and thereafter escalate annually. The Company assumed gas prices and operating costs would escalate annually beginning at current levels. Due to the volatility of oil and gas prices, it is possible that the Company's assumptions regarding oil and gas prices may change in the future and may result in future impairment provisions.

General and administrative expenses increased $4.4 million (14 percent), to $36.4 million for 1999 from $32.0 million for 1998, due primarily to the accrual of 1999 employee incentive bonuses and approximately $1.0 million in costs associated with the Company's efforts to prepare for Y2K. The Company implemented a bonus program effective for 1999 covering all U.S. employees designed to provide additional incentive to achieve certain corporate goals. The Company's G&A per BOE for 1999 was $1.46 ($1.34 before the 1999 bonus accrual) compared to $1.32 for 1998.

Depreciation, depletion and amortization decreased $1.2 million (1 percent), to $107.8 million for 1999 from $109.0 million for 1998, despite the three percent increase in total production due primarily to a lower DD&A rate per equivalent barrel for 1999 versus 1998. The Company's average DD&A rate per equivalent barrel produced decreased from $4.32 in 1998 to $4.15 in 1999 primarily as a result of the impact of the new production from the Company's El Huemul concession which has a substantially lower amortization rate and the effect of the U.S. impairments in 1998.

Interest expense increased $15.0 million (34 percent), to $58.7 million for 1999 from $43.7 million for 1998, due primarily to a 25 percent increase in the Company's total average outstanding debt as a result of the Company's 1998 total capital spending, including acquisitions, exceeding 1998's cash flow and an increase in its average interest rate on its outstanding debt. The Company's average interest rate for its outstanding debt for 1999 was 8.14 percent compared to 7.72 percent in 1998.

Capital Expenditures

During 2000, the Company's total oil and gas capital expenditures were $257.7 million. In North America, the Company's non-acquisition oil and gas capital expenditures totaled $63.0 million. Exploration activities accounted for $29.9 million of the North America capital expenditures with exploitation activities contributing $33.1 million. During 2000, the Company's international non-acquisition oil and gas capital expenditures totaled $103.2 million, consisting of $49.5 million in Argentina on exploitation activities, $28.7 million in Bolivia on exploitation and exploration activities, and $25.0 million in Yemen and Ecuador, principally on exploration. Total acquisition capital expenditures for 2000 of $91.4 million included $40.1 million for the acquisition of the Cuyo Basin concession in Argentina and $47.9 million allocated to proved properties as part of the acquisition of 100 percent of the outstanding common stock of Cometra Energy (Canada), Ltd., a privately-held Canadian company.

As of December 31, 2000, the Company had total unevaluated oil and gas property costs of approximately $47.2 million consisting of undeveloped leasehold costs of $30.0 million and exploratory drilling in progress of $17.2 million. Approximately $20.5 million of the unevaluated costs are associated with the Company's Yemen drilling program. Future exploration expense and earnings may be impacted to the extent any of the exploratory drilling is determined to be unsuccessful.

The timing of most of the Company's capital expenditures is discretionary with no material long-term capital expenditure commitments. Consequently, the Company has a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. The Company uses internally-generated cash flow to fund capital expenditures other than significant acquisitions. Of the Company's 2000 non-acquisition capital expenditures of $166.2 million, approximately 56 percent was spent on exploitation activities, including development and infill drilling, and approximately 44 percent was spent on exploration activities, a part of which satisfied all of the Company's previous exploration commitments in Bolivia, Ecuador and Yemen. The Company's preliminary capital expenditure budget for 2001 is currently set at $285 million, exclusive of acquisitions. The Company does not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. The Company is actively pursuing additional acquisitions of oil and gas properties. In addition to internally-generated cash flow and advances under its revolving credit facility, the Company may seek additional sources of capital to fund any future significant acquisitions (see "Liquidity"), however, no assurance can be given that sufficient funds will be available to fund the Company's desired acquisitions.

The Company's recent capital expenditure history is as follows:

	Years Ended December 31,		
(In thousands)	2000	1999	
Acquisition of oil and gas reserves.......................	$ 91,448	$ 166,787	$
Drilling..	121,911	46,280	
Acquisition of undeveloped acreage and seismic.............	18,084	12,742	
Workovers and recompletions................................	25,811	10,749	
Acquisition and construction of gathering systems..........	299	680	
Other..	419	927	
Total..	$ 257,972	$ 238,165	$

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Liquidity

Internally generated cash flow and the borrowing capacity under its revolving credit facility are the Company's major sources of liquidity. In addition, the Company may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions it might secure in the future and to maintain its financial flexibility.

In the past, the Company has accessed the public markets to finance significant acquisitions and provide liquidity for its future activities. Prior to 1999 in conjunction with the purchase of substantial oil and gas assets, the Company completed four public equity offerings as well as two public debt offerings, which provided the Company with aggregate net proceeds of $415 million.

On January 26, 1999, the Company issued $150 million of its 9 3/4% Senior Subordinated Notes due 2009 (the "9 3/4% Notes"). The 9 3/4% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2004. In addition, prior to February 1, 2002, the Company may redeem up to 33 1/3% of the 9 3/4% Notes with the proceeds of certain underwritten public offerings of the Company's common stock. The 9 3/4% Notes mature on June 30, 2009, with interest payable semiannually on June 30 and December 30 of each year. The net proceeds to the Company from the sale of the 9 3/4% Notes (approximately $146 million) were used to repay a portion of the existing indebtedness under the Company's revolving credit facility.

On June 21, 1999, the Company completed a public offering of 9,000,000 shares of common stock, all of which were sold by the Company. Net proceeds of approximately $81.2 million were used to partially fund the purchase of the El Huemul concession from Total and Repsol in early July 1999. Also in July 1999, in connection with the exercise by the underwriters of a portion of the over-allotment option, the Company sold an additional 240,800 shares of common stock using the additional $2.1 million of net proceeds to reduce a portion of the Company's existing indebtedness under its revolving credit facility.

Under the Second Amended and Restated Credit Agreement dated November 30, 2000, (the "Bank Facility"), certain banks have provided to the Company an unsecured revolving credit facility. The Bank Facility establishes a borrowing base (currently $625 million) determined by the banks' evaluation of the Company's oil and gas reserves. The amount available to be borrowed under the Bank Facility is limited to the lesser of the borrowing base or the facility size, which is currently set at $535 million.

Outstanding advances under the Bank Facility bear interest payable quarterly at a floating rate based on Bank of Montreal's alternate base rate (as defined) or, at the Company's option, at a fixed rate for up to six months based on the Eurodollar market rate ("LIBOR"). The Company's interest rate increments above the alternate base rate and LIBOR vary based on the level of outstanding senior debt to the borrowing base. As of February 28, 2001, the Company had elected a fixed rate based on LIBOR for a substantial portion of its outstanding advances, which resulted in an average interest rate of approximately 6.75 percent per annum. In addition, the Company must pay a commitment fee ranging from 0.325 to 0.50 percent per annum on the unused portion of the banks' commitment.

On a semiannual basis, the Company's borrowing base is redetermined by the banks based upon their review of the Company's oil and gas reserves. If the sum of outstanding senior debt exceeds the borrowing base, as redetermined, the Company must repay such excess. Final maturity of the Bank Facility is November 30, 2005.

At February 28, 2001, the unused portion of the Bank Facility was approximately $511 million. The unused portion of the Bank Facility and the Company's internally generated cash flow provide liquidity which may be used to finance future capital expenditures, including acquisitions. As additional acquisitions are made and such properties are added to the borrowing base, the banks' determination of the borrowing base and their commitments may be increased.

The Company's internally generated cash flow, results of operations and financing for its operations are dependent on oil and gas prices. For 2000, approximately 69 percent of the Company's production was oil. Realized oil prices for the year increased by 51 percent as compared to 1999 and total production on a BOE basis increased by 16 percent. As a result, the Company's earnings and cash flows have been materially increased compared to 1999. To the extent oil prices decline, the Company's earnings and cash flow from operations may be adversely impacted. However, the Company believes that its cash flows and unused availability under the Bank Facility are sufficient to fund its planned capital expenditures for the foreseeable future.

Inflation

In recent years inflation has not had a significant impact on the Company's operations or financial condition.

Income Taxes

The Company incurred a current provision for income taxes of approximately $68.9 million and $6.0 million for 2000 and 1999, respectively, and realized a current benefit of $4.1 million for 1998. The total provision for U.S. income taxes is based on the Federal corporate statutory income tax rate plus an estimated average rate for state income taxes. Earnings of the Company's foreign subsidiaries are subject to foreign income taxes. No U.S. deferred tax liability will be recognized related to the unremitted earnings of these foreign subsidiaries as it is the Company's intention, generally, to reinvest such earnings permanently.

The Company has an estimated U.S. Federal alternative minimum tax ("AMT") credit carryforward of approximately $4.8 million at December 31, 2000, which does not expire and is available to offset U.S. Federal regular income taxes in future years, but only to the extent that U.S. Federal regular income taxes exceed the AMT in such years. The Company fully utilized its $60.0 million U.S. Federal regular tax net operating loss ("NOL") carryforward and its AMT credit carryforward in 2000. The Company has a Bolivian income tax NOL of approximately $65 million which does not expire and can be used to offset future Bolivian tax liabilities of the Company.

Change in Accounting Principles

The Company adopted Securities and Exchange Commission Staff Accounting Bulletin No. 101, Revenue Recognition ("SAB No. 101"), in the fourth quarter of 2000, effective January 1, 2000. SAB No. 101 requires oil inventories held in storage facilities to be valued at cost. Cost is defined as lifting costs plus depreciation, depletion and amortization. The Company previously followed industry practice by valuing oil inventories at market. The cumulative effect reduced net income by $1.4 million, net of income tax effects of $0.6 million. Previously reported quarters during the year 2000 have been restated to give effect to this change in accounting principle. Additional volatility in quarterly and annually reported earnings may occur in the future as a result of the required adoption of SAB No. 101 and fluctuations in oil inventory levels.

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended in June 1999 by Statement No. 137, Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133 and in June 2000 by Statement No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities - an amendment of FASB Statement No. 133 ("SFAS No. 133"). SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

Upon adoption of SFAS No. 133 on January 1, 2001, the Company recorded a transition receivable of $16.3 million related to cash flow hedges in place that are used to reduce the volatility in commodity prices for portions of the Company's forecasted oil production. Additionally, the Company recorded, net of tax, an adjustment to accumulated other comprehensive income (Stockholders' Equity section of the balance sheet) of $10.6 million. The amount recorded to accumulated other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged are finalized.

Foreign Operations

For information on the Company's foreign operations, see "Foreign Currency and Operations Risk" under Item 7A of this Form 10-K.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

The Company's operations are exposed to market risks primarily as a result of changes in commodity prices, interest rates and foreign currency exchange rates. The Company does not use derivative financial instruments for speculative or trading purposes.

Commodity Price Risk

The Company produces, purchases and sells crude oil, natural gas, condensate, natural gas liquids and sulfur. As a result, the Company's financial results can be significantly impacted as these commodity prices fluctuate widely in response to changing market forces. The Company has previously engaged in oil and gas hedging activities and intends to continue to consider various hedging arrangements to realize commodity prices which it considers favorable. During 1999, the Company entered into various oil hedges (swap agreements) for a total of 1.8 MMBbls of oil at a weighted average price of $22.43 per Bbl (NYMEX reference price) for 2000. The fair value of commodity swap agreements is the amount at which they could be settled, based on quoted market prices. At December 31, 1999, the Company would have received approximately $700,000 to terminate its oil swap agreements then in place. During the first quarter of 2000, the Company entered into additional oil hedging contracts through December 31, 2000, covering an additional 3.6 MMBbls of oil and a weighted average NYMEX reference price of $25.77 per Bbl. The Company also entered into additional oil hedging contracts covering 3.9 MMBbls for various periods during 2000. In total, the Company entered into oil hedging contracts covering 2000 production of 9.3 MMBbls of oil at a weighted average NYMEX reference price of $26.85 per Bbl. During 2000, the Company entered into various oil hedges (swap agreements) for a total of 3.5 MMBbls of oil at a weighted average NYMEX reference price of $30.76 per Bbl for the calendar year 2001. At December 31, 2000, the Company would have received approximately $16.3 million to terminate its oil swap agreements then in place. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

Interest Rate Risk

The Company's interest rate risk exposure results primarily from short-term rates, mainly LIBOR based borrowings from its commercial banks. To reduce the impact of fluctuations in interest rates, the Company maintains a portion of its total debt portfolio in fixed rate debt. At December 31, 2000, the amount of the Company's fixed rate debt was approximately 86 percent of total debt. In the past, the Company has not entered into financial instruments such as interest rate swaps or interest rate lock agreements. However, it may consider these instruments to manage the impact of changes in interest rates based on management's assessment of future interest rates, volatility of the yield curve and the Company's ability to access the capital markets in a timely manner.

The following table provides information about the Company's long-term debt principal payments and weighted-average interest rates by expected maturity dates:

	2001	2002	2003	2004	2005	There-After	
Long-Term Debt:							
Fixed rate (in thousands)	-	-	-	-	$149,796	$249,433	$
Average interest rate	-	-	-	-	9.0%	9.3%	
Variable rate (in thousands)	-	-	-	-	$ 65,000	-	$
Average interest rate	-	-	-	-	(a)	-	

(a) LIBOR plus an increment, based on the level of outstanding senior debt to the borrowing base, up to a maximum increment of 2.0 percent. Current increment above LIBOR is 1.125 percent.

Foreign Currency and Operations Risk

International investments represent, and are expected to continue to represent, a significant portion of the Company's total assets. The Company has international operations in Argentina, Bolivia, Ecuador, Canada and Yemen. For 2000, the Company's operations in Argentina accounted for approximately 32 percent of the Company's revenues, 45 percent of the Company's operating income (before impairments of oil and gas properties) and 34 percent of its total assets. During 2000, the Company's operations in Argentina represented its only foreign operations accounting for more than 10 percent of its revenues or operating income (before impairments of oil and gas properties) or total assets.

The Company continues to identify and evaluate international opportunities but currently has no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, the Company's financial results could be affected by factors such as changes in foreign currency exchange rates, weak economic conditions or changes in the political climate in these foreign countries.

The Company believes Argentina offers a relatively stable political environment and does not anticipate any significant change in the near future. The current democratic form of government has been in place since 1983 and, since 1989, has pursued a steady process of privatization, deregulation and economic stabilization and reforms involving the reduction of inflation and public spending.

All of the Company's Argentine revenues are U.S. dollar based, while a large portion of its costs are denominated in Argentine pesos. The Argentina Central Bank is obligated by law to sell dollars at a rate of one Argentine peso to one U.S. dollar and has sought to prevent appreciation of the peso by buying dollars at rates of not less than 0.998 peso to one U.S. dollar. As a result, the Company believes that should any devaluation of the Argentine peso occur, its revenues would be unaffected and its operating costs would not be significantly increased. At the present time, there are no foreign exchange controls preventing or restricting the conversion of Argentine pesos into dollars.

Since the mid-1980's, Bolivia has been undergoing major economic reform, including the establishment of a free-market economy and the encouragement of foreign private investment. Economic activities that had been reserved for government corporations were opened to foreign and domestic private investments. Barriers to international trade have been reduced and tariffs lowered. A new investment law and revised codes for mining and the petroleum industry, intended to attract foreign investment, have been introduced.

On February 1, 1987, a new currency, the Boliviano ("Bs"), replaced the peso at the rate of one million pesos to one Boliviano. The exchange rate is set daily by the Government's exchange house, the Bolsin, which is under the supervision of the Bolivian Central Bank. Foreign exchange transactions are not subject to any controls. The US$:Bs exchange rate at December 31, 2000, was US$1:Bs 6.40. The Company believes that any currency risk associated with its Bolivian operations would not have a material impact on the Company's financial position or results of operations.

The new administration in Ecuador, led by President Gustavo Naboa, is undertaking a broad-based program of economic reform to stem the decline in economic activity and to lay the basis for renewed economic growth. The legal basis for many of the reforms is the Ley Fundamental para la Transformacion Economica del Ecuador (the "economic transformation law") enacted in March 2000, which mandated dollarization of the economy. As a result of this reform, all of the Company's Ecuadorian revenues and costs are U.S. dollar based. President Naboa continues to seek majority support and to overcome legal challenges necessary for the second phase of the economic transformation law (known as Trole II), which would bring significant tax and labor reform and a defined privatization program to increase inflows of foreign direct investment.

With the Cometra Acquisition in December 2000, the Company now has producing operations in Canada. The Company views the operating environment in Canada as stable and the economic stability as good. All of the Company's Canadian revenues and costs are denominated in Canadian dollars and while the value of the Canadian dollar does fluctuate in relation to U.S. dollar, the

Company believes that any currency risk associated with its Canadian operations would not have a material impact on the Company's financial position or results of operations.

Item 8. Financial Statements and Supplementary Data.

The Consolidated Financial Statements and notes thereto, the report of independent public accountants and the supplementary financial and operating information are included elsewhere in this Form 10-K.

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

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The information required by this Item with respect to the Company's directors is incorporated by reference from the sections of the Company's definitive Proxy Statement for its 2001 Annual Meeting of Stockholders (the "Proxy Statement") entitled "Election of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance." The information required by this Item with respect to the Company's executive officers appears at Item 4A of Part I of this Form 10-K.

Item 11. Executive Compensation.

The information required by this Item is incorporated by reference from the section of the Proxy Statement entitled "Executive Compensation."

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

The information required by this Item is incorporated by reference from the section of the Proxy Statement entitled "Principal Stockholders and Security Ownership of Management."

Item 13. Certain Relationships and Related Transactions.

The information required by this Item is incorporated by reference from the section of the Proxy Statement entitled "Certain Transactions."

PART IV

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

(a) (1) Financial Statements:

The financial statements of the Company and its subsidiaries and report of independent public accountants listed in the accompanying Index to Financial Statements are filed as a part of this Form 10-K.

(2) Financial Statements Schedules:

All schedules are omitted as inapplicable or because the required information is contained in the financial statements or included in the notes thereto.

(3) Exhibits:

The following documents are included as exhibits to this Form 10-K. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, such exhibit is filed herewith.

3.1 Restated Certificate of Incorporation, as amended, of the Company (Filed as Exhibit 3.2 to the Company's report on Form 10-Q for the quarter ended June 30, 2000, filed August 11, 2000).

3.2 Restated By-laws of the Company (Filed as Exhibit 3.2 to the Company's Registration Statement on Form S-1, Registration No. 33- 35289 (the "S-1 Registration Statement")).

4.1 Form of stock certificate for Common Stock, par value $.005 per share (Filed as Exhibit 4.1 to the S-1 Registration Statement).

4.2 Indenture dated as of December 20, 1995, between The Chase Manhattan Bank (formerly Chemical Bank), as Trustee, and the Company (Filed as Exhibit 99.1 to the Company's report on Form 8-K filed January 16, 1996).

4.3 Indenture dated as of February 5, 1997, between The Chase Manhattan Bank, as Trustee, and the Company (Filed as Exhibit 4.3 to the Company's report on Form 10-K for the year ended December 31, 1996, filed March 27, 1997).

4.4 Indenture dated as of January 26, 1999, between The Chase Manhattan Bank, as Trustee, and the Company (Filed as Exhibit 4.4 to the Company's report on Form 10-K for the year ended December 31, 1998, filed March 12, 1999).

4.5 Rights Agreement, dated March 16, 1999, between the Company and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (Filed as Exhibit 4.1 to the Company's Registration Statement on Form 8-A, filed March 22, 1999).

4.6 Certificate of Designation of Series A Junior Participating Preferred Stock of the Company (Filed as Exhibit 3.3 to the Company's Registration Statement on Form S-3, Registration No. 333-77619).

10.1* Employment and Noncompetition Agreement dated January 7, 1987, between the Company and Charles C. Stephenson, Jr. (Filed as Exhibit 10.19 to the S-1 Registration Statement).

10.2* Form of Indemnification Agreement between the Company and certain of its officers and directors (Filed as Exhibit 10.23 to the S-1 Registration Statement).

10.3* Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 4(d) to the Company's Registration Statement on Form S-8, Registration No. 33-37505).

10.4* Amendment No. 1 to Vintage Petroleum, Inc. 1990 Stock Plan, effective January 1, 1991 (Filed as Exhibit 10.15 to the Company's report on Form 10-K for the year ended December 31, 1991, filed March 30, 1992).

10.5* Amendment No. 2 to Vintage Petroleum, Inc. 1990 Stock Plan dated February 24, 1994 (Filed as Exhibit 10.15 to the Company's report on Form 10-K for the year ended December 31, 1993, filed March 29, 1994).

10.6* Amendment No. 3 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 15, 1996 (Filed as Exhibit A to the Company's Proxy Statement for Annual Meeting of Stockholders dated April 1, 1996).

10.7* Amendment No. 4 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 11, 1998 (Filed as Exhibit A to the Company's Proxy Statement for Annual Meeting of Stockholders dated March 31, 1998).

10.8* Amendment No. 5 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 16, 1999 (Filed as Exhibit A to the Company's Proxy Statement for Annual Meeting of Stockholders dated March 31, 1999).

10.9* Amendment No. 6 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 17, 2000 (Filed as Exhibit A to the Company's Proxy Statement for Annual Meeting of Stockholders dated March 30, 2000).

10.10* Vintage Petroleum, Inc. 401(k) Plan (Filed as Exhibit 4(C) to the Company's Registration Statement on Form S-8, Registration No. 33-55706).

10.11* Vintage Petroleum, Inc. Non-Management Director Stock Option Plan (Filed as Exhibit 10.18 to the Company's report on Form 10-K for the year ended December 31, 1992, filed March 31, 1993 (the "1992 Form 10-K")).

10.12* Form of Incentive Stock Option Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.20 to the Company's report on Form 10-K for the year ended December 31, 1990, filed April 1, 1991).

10.13* Form of Non-Qualified Stock Option Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.20 to the 1992 Form 10-K).

10.14* Form of Non-Qualified Stock Option Agreement for non-employee directors under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.13 to the Company's report on Form 10-K for the year ended December 31, 1999, filed March 13, 2000).

10.15 Second Amended and Restated Credit Agreement dated as of November 30, 2000, among the Company, as borrower, and certain commercial lending institutions, as lenders, Bank of Montreal, as administrative agent, Bank of America, N.A., as syndication agent, Societe Generale, Southwest Agency, as documentation agent, and ABN AMRO Bank, N.A., as managing agent.

21. Subsidiaries of the Company.

23.1 Consent of Arthur Andersen LLP.

23.2 Consent of Netherland, Sewell & Associates, Inc.

23.3 Consent of DeGolyer and MacNaughton.

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* Management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K.

Form 8-K dated October 12, 2000, was filed October 19, 2000, to report under Item 5 the Company's recent hedging activities and the Company's press releases dated October 12 and 17, 2000, announcing Yemen drilling update and Ecuador exploratory well results.

No other reports on Form 8-K were filed during the fourth quarter of the fiscal year ended December 31, 2000.

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.

VINTAGE PETROLEUM, INC.

Date: March 9, 2001

By: /s/ C. C. Stephenson, Jr.
C. C. Stephenson, Jr.
Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ C. C. Stephenson, Jr. C. C. Stephenson, Jr.	Director and Chairman of the Board	March 9, 20
/s/ S. Craig George S. Craig George	Director, President and Chief Executive Officer (Principal Executive Officer)	March 9, 20
/s/ William L. Abernathy William L. Abernathy	Director, Executive Vice President and Chief Operating Officer	March 9, 20
/s/ William C. Barnes William C. Barnes	Director, Executive Vice President, Chief Financial Officer, Secretary and Treasurer (Principal Financial Officer)	March 9, 20
/s/ Bryan H. Lawrence	Director	March 9, 20

Bryan H. Lawrence		
/s/ John T. McNabb, II	Director	March 9, 20
John T. McNabb, II		
/s/ Michael F. Meimerstorf	Vice President and Controller	March 9, 20
Michael F. Meimerstorf	(Principal Accounting Officer)	

INDEX TO FINANCIAL STATEMENTS

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

AUDITED FINANCIAL STATEMENTS OF VINTAGE PETROLEUM, INC. AND SUBSIDIARIES:

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors and Stockholders
of Vintage Petroleum, Inc.:

We have audited the accompanying consolidated balance sheets of Vintage Petroleum, Inc. (a Delaware corporation) and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of operations, changes in stockholders' equity and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Vintage Petroleum, Inc. and subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Tulsa, Oklahoma
February 16, 2001

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In thousands, except shares
and per share amounts)

ASSETS

	Dec
	2000
CURRENT ASSETS:	
Cash and cash equivalents	$ 19,506
Accounts receivable -	
Oil and gas sales	146,770
Joint operations	6,267
Prepaids and other current assets	13,946
Total current assets	186,489
PROPERTY, PLANT AND EQUIPMENT, at cost:	
Oil and gas properties, successful efforts method	1,734,003
Oil and gas gathering systems and plants	19,252
Other	19,636
	1,772,891
Less accumulated depreciation, depletion and amortization	667,837
	1,105,054
OTHER ASSETS, net	46,854
	$1,338,397

LIABILITIES AND STOCKHOLDERS' EQUITY

CURRENT LIABILITIES:	
Revenue payable	$ 60,519
Accounts payable - trade	43,225
Current income taxes payable	43,187
Other payables and accrued liabilities	65,361
Total current liabilities	212,292

LONG-TERM DEBT	464,229
DEFERRED INCOME TAXES	33,252
OTHER LONG-TERM LIABILITIES	3,767
COMMITMENTS AND CONTINGENCIES (Note 4)	
STOCKHOLDERS' EQUITY, per accompanying statements:	
Preferred stock, $.01 par, 5,000,000 shares authorized, zero shares issued and outstanding	-
Common stock, $.005 par, 160,000,000 and 80,000,000 shares authorized, 62,801,416 and 62,407,866 shares issued and outstanding	314
Capital in excess of par value	319,893
Retained earnings	303,449
Accumulated other comprehensive income	1,201
	624,857
	$1,338,397

The accompanying notes are an integral part of these statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For
	2000
REVENUES:	
Oil and gas sales	$ 680,350
Gas marketing	128,836
Oil and gas gathering	19,998
Gain (loss) on disposition of assets	(1,731
Other income (expense)	(21,272
	806,181
COSTS AND EXPENSES:	
Lease operating, including production taxes	159,638
Exploration costs	25,242
Impairment of oil and gas properties	225
Gas marketing	123,787
Oil and gas gathering	17,052
General and administrative	41,416
Depreciation, depletion and amortization	100,109
Interest	48,437
	515,906
Income (loss) before income taxes and cumulative effect of change in accounting principle	290,275

PROVISION (BENEFIT) FOR INCOME TAXES:	
Current	68,858
Deferred	24,102
	92,960
Income (loss) before cumulative effect of change in accounting principle	197,315
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, net of income taxes of $644	(1,422
NET INCOME (LOSS)	$ 195,893
BASIC INCOME (LOSS) PER SHARE:	
Income (loss) before cumulative effect of change in accounting principle	$ 3.15
Cumulative effect of change in accounting principle	(0.02
Net income (loss)	$ 3.13
DILUTED INCOME (LOSS) PER SHARE:	
Income (loss) before cumulative effect of change in accounting principle	$ 3.08
Cumulative effect of change in accounting principle	(0.02
Net income (loss)	$ 3.06
Weighted Average Common Shares Outstanding:	
Basic	62,644
Diluted	63,963

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(In thousands, except per share amounts)

	Common Stock		Capital In Excess of Par Value
	Shares	Amount	
BALANCE AT DECEMBER 31, 1997	51,559	$ 258	$202,008
Net loss	-	-	-
Issuance of common stock	1,325	7	26,493
Exercise of stock options and resulting tax effects	223	1	2,235
Cash dividends declared ($.09 per share)	-	-	-
BALANCE AT DECEMBER 31, 1998	53,107	266	230,736

Net income	-	-	-
Issuance of common stock	9,241	46	83,284
Exercise of stock options and resulting tax effects	60	-	470
BALANCE AT DECEMBER 31, 1999	62,408	312	314,490
Comprehensive income:			
Net income	-	-	-
Foreign currency translation adjustment	-	-	-
Total comprehensive income	-	-	-
Exercise of stock options and resulting tax effects	393	2	5,403
Cash dividends declared ($.14 per share)	-	-	-
BALANCE AT DECEMBER 31, 2000	62,801	$ 314	$319,893

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For T
	2000
CASH FLOWS FROM OPERATING ACTIVITIES:	
Net income (loss)	$ 195,893
Adjustments to reconcile net income (loss) to cash provided by operating activities, net of companies acquired -	
Depreciation, depletion and amortization	100,109
Impairment of oil and gas properties	225
Exploration costs	25,242
Provision (benefit) for deferred income taxes	24,102
Cumulative effect of change in accounting principle	1,422
(Gain) loss on disposition of assets	1,731
	348,724
Decrease (increase) in receivables	(56,179)
Increase (decrease) in payables and accrued liabilities	99,514
Income tax refund receivable	-
Other	3,628
Cash provided by operating activities	395,687

CASH FLOWS FROM INVESTING ACTIVITIES:	
Capital expenditures -	
Oil and gas properties	(209,552)
Gathering systems and other	(2,633)
Proceeds from sales of oil and gas properties	998
Purchase of companies, net of cash acquired	(46,199)
Other	(4,132)
Cash used by investing activities	(261,518)
CASH FLOWS FROM FINANCING ACTIVITIES:	
Sale of common stock	3,492
Sale of 9 3/4% Senior Subordinated Notes Due 2009	-
Advances on revolving credit facility and other borrowings	70,388
Payments on revolving credit facility and other borrowings	(224,343)
Dividends paid	(6,887)
Cash provided (used) by financing activities	(157,350)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(23,181)
CASH AND CASH EQUIVALENTS, beginning of year	42,687
CASH AND CASH EQUIVALENTS, end of year	$ 19,506

The accompanying notes are an integral part of these statements.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the Years Ended December 31, 2000, 1999 and 1998

1. Business and Significant Accounting Policies

Consolidation

Vintage Petroleum, Inc. is an independent energy company with operations primarily in the exploration and production, gas marketing and gathering segments of the oil and gas industry. Approximately 98 percent of the Company's operations are within the exploration and production segment based on 2000 operating income before impairments of oil and gas properties and losses on asset sales. Its core areas of exploration and production operations include the West Coast, Gulf Coast, East Texas and Mid-Continent areas of the United States, the San Jorge Basin and Cuyo Basin of Argentina, the Chaco Basin in Bolivia, Canada and Ecuador.

The consolidated financial statements include the accounts of Vintage Petroleum, Inc. and its wholly- and majority-owned subsidiaries and its proportionately consolidated general partner interests in various joint ventures (collectively, the "Company"). All significant intercompany accounts and transactions have been eliminated in consolidation.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Certain 1999 and 1998 amounts have been reclassified to conform with the 2000 presentation. These reclassifications have no impact on net income (loss).

Oil and Gas Properties

Under the successful efforts method of accounting, the Company capitalizes all costs related to property acquisitions and successful exploratory wells, all development costs and the costs of support equipment and facilities. All costs related to unsuccessful exploratory wells are expensed when such wells are determined to be non-productive; other exploration costs, including geological and geophysical costs, are expensed as incurred. The Company recognizes gain or loss on the sale of properties on a field basis.

Unproved leasehold costs are capitalized and are reviewed periodically for impairment. Costs related to impaired prospects are charged to expense. If oil and gas prices decline in the future, some of these unproved prospects may not be economic to develop, which could lead to increased impairment expense.

Costs of development dry holes and proved leaseholds are amortized on the unit-of-production method based on proved reserves on a field basis. The depreciation of capitalized production equipment and drilling costs is based on the unit-of-production method using proved developed reserves on a field basis. Estimated abandonment costs, net of salvage value, are included in the depreciation and depletion calculation.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The Company reviews its proved oil and gas properties for impairment on a field basis. For each field, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of those properties may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the estimated future net revenues from production of total proved oil and gas reserves over the economic life of the reserves, based on the Company's expectations of future oil and gas prices and costs. In estimating the future net revenues at December 31, 2000, the Company assumed that the current oil and gas price environment would return to more historical levels over a short period of time and thereafter, escalate annually. The Company assumed operating costs would escalate annually beginning at current levels. Due to the volatility of oil and gas prices, it is possible that the Company's assumptions regarding oil and gas prices may change in the future and may result in future impairment provisions. The Company recorded impairment provisions related to its proved oil and gas properties of $0.2 million, $3.3 million and $70.9 million in 2000, 1999 and 1998, respectively.

Revenue Recognition

Natural gas revenues are recorded using the sales method. Under this method, the Company recognizes revenues based on actual volumes of gas sold to purchasers. The Company and other joint interest owners may sell more or less than their entitlement share of the natural gas volumes produced. A liability is recorded and revenue is deferred if the Company's excess sales of natural gas volumes exceed its estimated remaining recoverable reserves. Oil revenues are recognized at the time of delivery to pipelines or at the time of physical transfer to purchaser.

Hedging

The Company periodically uses hedges (swap agreements) to reduce the impact of oil and natural gas price fluctuations. Gains or losses on swap agreements are recognized as an adjustment to sales revenue when the related transactions being hedged are finalized. Gains or losses from swap agreements that do not qualify for accounting treatment as hedges are recognized currently as other income or expense. The cash flows from such agreements are included in operating activities in the consolidated statements of cash flows.

The Company participated in oil hedges covering 9.3 MMBbls during 2000. The impact of these hedges reduced the Company's U.S. average oil price by $4.10 to $22.85 per Bbl and its overall average oil price by $1.86 to $25.55 per Bbl. The Company participated in oil hedges covering 1.84 MMBbls during 1999. The impact of the 1999 hedges reduced the Company's U.S. average oil price by 11 cents to $15.92 per Bbl and its overall average oil price by six cents to $16.92 per Bbl. The Company was not a party to any oil hedges in 1998.

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended in June 1999 by Statement No. 137, Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133 and in June 2000 by Statement No. 138, Accounting for Certain Derivative Instruments and Certain Hedging Activities - an amendment of FASB Statement No. 133 ("SFAS No. 133"). SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement. Companies must formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

Upon adoption of SFAS No. 133 on January 1, 2001, the Company recorded a transition receivable of $16.3 million related to cash flow hedges in place that are used to reduce the volatility in commodity prices for portions of the Company's forecasted oil production. Additionally, the Company recorded, net of tax, an adjustment to accumulated other comprehensive income (Stockholders' Equity section of the balance sheet) of $10.6 million. The amount recorded to accumulated other comprehensive income will be relieved over time and taken to the income statement as the physical transactions being hedged are finalized.

Depreciation

Depreciation of property, plant and equipment (other than oil and gas properties) is provided using both straight-line and accelerated methods based on estimated useful lives ranging from three to seven years.

Income Taxes

Deferred income taxes are provided on transactions which are recognized in different periods for financial and tax reporting purposes. Such temporary differences arise primarily from the deduction of certain oil and gas exploration and development costs which are capitalized for financial reporting purposes and differences in the methods of depreciation.

Statements of Cash Flows

Cash equivalents consist of highly liquid money-market mutual funds and bank deposits with initial maturities of three months or less. At December 31, 1999, the Company had approximately $40 million in escrow accounts primarily related to potential like-kind exchange transactions.

During the years ended December 31, 2000, 1999 and 1998, the Company made cash payments for interest totaling $48.3 million, $56.8 million and $42.4 million, respectively. Cash payments for U.S. income taxes of $19.8 million and $1.5 million were made during 2000 and 1998, respectively. No cash payments for U.S. income taxes were made during 1999. The Company made cash payments of $9.5 million during 2000 for foreign income taxes, primarily in Argentina. No cash payments were made during 1999 for foreign income taxes. Cash payments of $1.3 million were made during 1998 for foreign tax withholdings.

In November 1998, the Company purchased 100 percent of the outstanding common stock of Elf Hydrocarbures Equateur, S.A., a French subsidiary of Elf Aquitaine ("Elf"). Total consideration included cash and common stock of the Company. The value of the non-cash consideration was $26.5 million and is not reflected in the Company's 1998 Statement of Cash Flows.

In December 2000, the Company purchased 100 percent of the outstanding common stock of Cometra Energy (Canada), Ltd. Total purchase price included both cash and the assumption of $7.6 million in net liabilities. These net liabilities are not reflected in the Company's 2000 Statement of Cash Flows.

Earnings Per Share

Basic earnings (loss) per common share were computed by dividing net income (loss) by the weighted average number of shares outstanding during the period. Diluted earnings per common share for 2000 and 1999 were computed assuming the exercise of all dilutive options, as determined by applying the treasury stock method. For 1998, the computation of diluted loss per share was antidilutive; therefore, the amounts reported for basic and diluted loss per share were the same. Had the Company been in a net income position for 1998, the Company's diluted weighted average outstanding common shares as calculated under Statement of Financial Accounting Standards No. 128, Earnings Per Share, would have been 54,604,530 with an additional 1,629,000 shares at an average exercise price of $17.83 that would have been antidilutive. In addition, for the years ended December 31, 2000 and 1999, the Company had outstanding stock options for 714,000 and 1,635,000 additional shares of the Company's common stock, respectively, with average exercise prices of $20.19 and $17.70, respectively, which were antidilutive.

General and Administrative Expense

The Company receives fees for operation of jointly-owned oil and gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $3.3 million, $2.9 million and $2.7 million in 2000, 1999 and 1998, respectively.

Lease Operating Expense

For the years ended December 31, 2000, 1999 and 1998, the Company recorded in lease operating expenses gross production taxes of $17.4 million, $7.5 million and $7.4 million, respectively, and transportation and storage expenses of $10.5 million, $6.2 million and $4.4 million, respectively.

Revenue Payable

Amounts payable to royalty and working interest owners resulting from sales of oil and gas from jointly-owned properties and from purchases of oil and gas by the Company's marketing and gathering segments are classified as revenue payable in the accompanying financial statements.

Accounts Receivable

The Company's oil and gas, gas marketing and gathering sales are made to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates, independent marketing companies and major oil companies. The Company's joint operations accounts receivable are from a large number of major and independent oil companies, partnerships, individuals and others who own interests in the properties operated by the Company.

Foreign Currency

Foreign currency transactions and financial statements are translated in accordance with Statement of Financial Accounting Standards No. 52, Foreign Currency Translation. All of the Company's subsidiaries use the U.S. dollar as their functional currency, except for the Company's Canadian subsidiary, which uses the Canadian dollar. Adjustments arising from translation of the Canadian subsidiary's financial statements are reflected in accumulated other comprehensive income. Transaction gains and losses that arise from exchange rate fluctuations applicable to transactions denominated in a currency other than the Company's or subsidiary's functional currency are included in the results of operations as incurred.

Cumulative Effect of Change in Accounting Principle

The Company adopted Securities and Exchange Commission Staff Accounting Bulletin No. 101, Revenue Recognition ("SAB No. 101"), in the fourth quarter of 2000, effective January 1, 2000. SAB No. 101 requires oil inventories held in storage facilities to be valued at cost. Cost is defined as lifting costs plus depreciation, depletion and amortization. The Company previously followed industry practice by valuing oil inventories at market. The cumulative effect reduced net income by $1.4 million, net of income tax effects of $0.6 million. Previously reported quarters during the year 2000 have been restated to give effect to this change in accounting principle. Additional volatility in quarterly and annually reported earnings may occur in the future as a result of the required adoption of SAB No. 101 and fluctuations in oil inventory levels.

Transportation and Storage Costs

The Company adopted Emerging Issues Task Force Issue 00-10, Accounting for Shipping and Fees and Costs ("EITF 00-10") in the fourth quarter of 2000. EITF 00-10 requires that transportation and storage costs be shown as an expense in the statement of operations and not deducted from revenues. The Company previously followed industry practice by deducting transportation and storage costs from revenues. The Company now records transportation and storage costs as lease operating costs. Fiscal years 1999 and 1998 have been restated to reflect the adoption of EITF 00-10. The adoption of EITF 00-10 did not impact net income (loss).

Comprehensive Income

The Company applies the provisions of Statement of Financial Accounting Standards No. 130, Reporting Comprehensive Income ("SFAS No. 130"). The Company had no non-owner changes in equity other than net income and losses during the years ended December 31, 1999 and 1998. The Company had foreign currency translation adjustments of $1.2 million for the year ended December 31, 2000, which it has included in accumulated other comprehensive income in the Stockholders' Equity section of the accompanying balance sheet.

2. Long-Term Debt

Long-term debt at December 31, 2000 and 1999, consisted of the following:

(In thousands)	2000	1999
Revolving credit facility	$ 65,000	$ 226,20
Senior subordinated notes:		
9% Notes due 2005, less unamortized discount	149,796	149,75
8 5/8% Notes due 2009, less unamortized discount	99,433	99,36
9 3/4% Notes due 2009	150,000	150,00
	$ 464,229	$ 625,31

The Company has no long-term debt maturities prior to November 30, 2005. The Company had $5.0 million and $5.9 million of accrued interest payable related to its long-term debt at December 31, 2000 and 1999, respectively, included in other payables and accrued liabilities.

Revolving Credit Facility

The Company has available an unsecured revolving credit facility under the Second Amended and Restated Credit Agreement dated November 30, 2000 (the "Bank Facility"), between the Company and certain banks. The Bank Facility establishes a borrowing base (currently $625 million) based on the banks' evaluation of the Company's oil and gas reserves. The amount available to be borrowed under the Bank Facility is limited to the lesser of the borrowing base or the facility size, which is currently set at $535 million.

Outstanding advances under the Bank Facility bear interest payable quarterly at a floating rate based on Bank of Montreal's alternate base rate (as defined) or, at the Company's option, at a fixed rate for up to six months based on the Eurodollar market rate ("LIBOR"). The Company's interest rate increments above the alternate base rate and LIBOR vary based on the level of outstanding senior debt to the borrowing base. In addition, the Company must pay a commitment fee ranging from 0.325 to 0.50 percent per annum on the unused portion of the banks' commitment. Total outstanding advances at December 31, 2000, were $65.0 million at an average interest rate of approximately 8.81 percent.

On a semiannual basis, the Company's borrowing base is redetermined by the banks based upon their review of the Company's oil and gas reserves. The Company's borrowing base was last redetermined in November 2000. If the sum of outstanding senior debt exceeds the borrowing base, as redetermined, the Company must repay such excess. Any principal advances outstanding at maturity on November 30, 2005, will be due immediately.

The terms of the Bank Facility impose certain restrictions on the Company regarding the pledging of assets and limitations on additional indebtedness. In addition, the Bank Facility requires the maintenance of a minimum current ratio (as defined) and tangible net worth (as defined) of not less than $375 million plus 75 percent of the net proceeds of any future equity offerings less any impairment writedowns required by GAAP or by the Securities and Exchange Commission and excluding any impact related to SFAS No. 133.

Senior Subordinated Notes

On December 20, 1995, the Company issued $150 million of its 9% Senior Subordinated Notes due 2005 (the "9% Notes"). The 9% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after December 15, 2000. The 9% Notes mature on December 15, 2005, with interest payable semiannually on June 15 and December 15 of each year.

On February 5, 1997, the Company issued $100 million of its 8 5/8% Senior Subordinated Notes due 2009 (the "8 5/8% Notes"). The 8 5/8% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2002. The 8 5/8% Notes mature on February 1, 2009, with interest payable semiannually on February 1 and August 1 of each year.

On January 26, 1999, the Company issued $150 million of its 9 3/4% Senior Subordinated Notes due 2009 (the "9 3/4% Notes"). The 9 3/4% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2004. In addition, prior to February 1, 2002, the Company may redeem up to 33 1/3% of the 9 3/4% Notes with the proceeds of certain underwritten public offerings of the Company's common stock. The 9 3/4% Notes mature on June 30, 2009, with interest payable semiannually on June 30 and December 30 of each year. The net proceeds to the Company from the sale of the 9 3/4% Notes (approximately $146 million) were used to repay a portion of the existing indebtedness under the Company's Bank Facility.

The 9% Notes, 8 5/8% Notes and 9 3/4% Notes (collectively, the "Notes") are unsecured senior subordinated obligations of the Company, rank subordinate in right of payment to all senior indebtedness (as defined) and rank pari passu with each other. Upon a change in control (as defined) of the Company, holders of the Notes may require the Company to repurchase all or a portion of the Notes at a purchase price equal to 101 percent of the principal amount thereof, plus accrued and unpaid interest. The indentures for the Notes contain limitations on, among other things, additional indebtedness and liens, the payment of dividends and other distributions, certain investments and transfers or sales of assets.

3. Capital Stock

Public Offerings and Other Issuances

On November 4, 1998, the Company issued 1,325,000 shares of common stock to Elf as partial consideration for the acquisition of its French subsidiary, Elf Hydrocarbures Equateur, S.A., which owns producing oil properties and undeveloped acreage in Ecuador.

On March 16, 1999, the Company's Board of Directors (the "Board") adopted a stockholder rights plan and declared a dividend distribution of one Preferred Share Purchase Right ("Right") on each outstanding share of the Company's common stock which was made on April 5, 1999, to stockholders of record on that date. The Rights will expire on April 5, 2009.

The Rights will be exercisable only if a person or group acquires 15 percent or more of the Company's common stock or announces a tender offer, the consummation of which would result in ownership by a person or group of 15 percent or more of the Company's common stock. Each Right will entitle stockholders to buy one one-thousandth of a share of a new series of junior participating preferred stock at an exercise price of $60. If the Company is acquired in a merger or other business combination transaction after a person has acquired 15 percent or more of the Company's outstanding common stock, each Right will entitle its holder to purchase, at the Right's then-current exercise price, a number of the acquiring company's common shares having a market value of twice such price. In addition, if a person or group acquires 15 percent or more of the Company's outstanding common stock, each Right will entitle its holder (other than such person or members of such group) to purchase, at the Right's then-current exercise price, a number of the Company's common shares having a market value of twice such price. Prior to the acquisition by a person or group of beneficial ownership of 15 percent or more of the Company's common stock, the Rights are redeemable for one cent per Right at the option of the Board.

On June 21, 1999, the Company completed a public offering of 9,000,000 shares of newly issued common stock. Net proceeds of approximately $81.2 million were used to partially fund the purchase of certain oil and gas properties from a subsidiary of Total Fina S.A. and a subsidiary of Repsol S.A. in early July 1999. On July 15, 1999, in connection with the exercise by the underwriters of a portion of the over-allotment option, the Company sold an additional 240,800 shares of common stock using the additional $2.1 million of net proceeds to reduce a portion of the Company's existing indebtedness under its revolving credit facility.

Stock Plans

The Company has two fixed plans which reserve shares of common stock for issuance to key employees and non-management directors. The Company accounts for these plans under Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees ("APB No. 25") and has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation ("SFAS No. 123"). Accordingly, no compensation cost has been recognized. Had compensation cost for these plans been determined consistent with the provisions of SFAS No. 123, the Company's net income (loss) and earnings (loss) per share would have been adjusted to the following pro forma amounts:

(In thousands, except per share amounts)	2000	1999	1998
Net income (loss) - as reported........................	$195,893	$73,371	$(87,66
Net income (loss) - pro forma..........................	193,252	71,130	(89,75
Earnings (loss) per share - as reported:			
Basic...	3.13	1.27	(1.6
Diluted...	3.06	1.24	(1.6
Earnings (loss) per share - pro forma:			
Basic...	3.08	1.23	(1.7
Diluted...	3.02	1.20	(1.7

The pro forma effect on net income (loss) for 2000, 1999 and 1998 may not be representative of the pro forma effect on net income in future years because SFAS No. 123 has not been applied to options granted prior to January 1, 1995.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The weighted average assumptions used for options granted in 2000 include a dividend yield of 0.6 percent, expected volatility of approximately 46.7 percent, a risk-free interest rate of approximately 6.3 percent and expected lives of 4.4 years. The weighted average assumptions used for options granted in 1999 include a dividend yield of 0.6 percent, expected volatility of approximately 38.6 percent, a risk-free interest rate of approximately 5.1 percent and expected lives of 4.2 years. The weighted average assumptions used for options granted in 1998 include a dividend yield of 0.6 percent, expected volatility of approximately 27.1 percent, a risk-free interest rate of approximately 5.7 percent and expected lives of 4.2 years.

Under the 1990 Stock Plan, as amended (the "1990 Plan"), ten percent of the total number of outstanding shares of common stock less the total number of shares of common stock subject to outstanding awards under any other stock-based plan for employees or directors of the Company are available for issuance to key employees and directors of the Company. The 1990 Plan permits the granting of any or all of the following types of awards: (a) stock options, (b) stock appreciation rights and (c) restricted stock. As of December 31, 2000, awards for a total of 1,235,550 shares of common stock remain available for grant under the 1990 Plan.

The 1990 Plan is administered by the Board. Subject to the terms of the 1990 Plan, the Board has the authority to determine plan participants, the types and amounts of awards to be granted and the terms, conditions and provisions of awards. Options granted pursuant to the 1990 Plan may, at the discretion of the Board, be either incentive stock options or non-qualified stock options. The exercise price of incentive stock options may not be less than the fair market value of the common stock on the date of grant and the term of the option may not exceed 10 years. In the case of non-qualified stock options, the exercise price may not be less than 85 percent of the fair market value of the common stock on the date of grant. Any stock appreciation rights granted under the 1990 Plan will give the holder the right to receive cash in an amount equal to the difference between the fair market value of the share of common stock on the date of exercise and the exercise price. Restricted stock under the 1990 Plan will generally consist of shares which may not be disposed of by participants until certain restrictions established by the Board lapse.

Under the Non-Management Director Stock Option Plan (the "Director Plan"), 60,000 shares of common stock are available for issuance to the outside directors of the Company. Each outside director receives an initial option to purchase 5,000 shares of common stock during the director's first year of service to the Company. Annually thereafter, options to purchase 1,000 shares of common stock are to be granted to each outside director. Options granted pursuant to the Director Plan are non-qualified stock options with terms not to exceed 10 years and the option exercise price must equal the fair market value of the common stock on the date of grant. As of December 31, 2000, options for a total of 18,000 shares of common stock remain available for grant under the Director Plan.

The following is an analysis of all option activity under the 1990 Plan and the Director Plan for 2000, 1999 and 1998:

	2000		1999	
	Shares	Wtd. Avg. Exercise Price	Shares	Wtd. Exer Pri
Beginning stock options outstanding..............	4,616,142	$11.61	3,606,142	$
Stock options granted...........................	853,000	19.62	1,070,000	
Stock options canceled..........................	(49,000)	13.70	-	
Stock options exercised.........................	(393,550)	8.87	(60,000)	
Ending stock options outstanding.................	5,026,592	$13.16	4,616,142	$
Ending stock options exercisable.................	2,238,142	$10.89	1,967,256	$
Weighted average fair value of options granted................................	$ 9.02		$ 2.24	

Of the 5,026,592 options outstanding at December 31, 2000: (a) 2,411,342 options have exercise prices between $5.94 and $9.81, with a weighted average exercise price of $8.15 and a weighted average contractual life of 5.8 years (1,377,342 of these options are exercisable currently at a weighted average price of $8.83); (b) 964,250 options have exercise prices between $10.00 and $15.50, with a weighted average exercise price of $14.25 and a weighted average contractual life of 5.7 years (834,100 of these options are exercisable currently at a weighted average price of $14.06); and (c) 1,651,000 options have exercise prices between $16.06 and $22.94, with a weighted average exercise price of $19.84 and a weighted average contractual life of 8.4 years (26,700 of these options are exercisable currently at a weighted average price of $18.36).

All of the outstanding options are exercisable at various times in years 2001 through 2010. All incentive stock options and non-qualified stock options were granted at fair market value on the date of grant. As of December 31, 2000, no awards other than incentive and non-qualified stock options have been granted under the 1990 Plan. Generally, options granted under the 1990 Plan have a 10-year term and provide for vesting after three years.

At December 31, 2000, a total of 6,280,142 shares of the Company's common stock are reserved for issuance pursuant to the 1990 Plan and the Director Plan.

Preferred Stock

Preferred stock at December 31, 2000, consists of 5,000,000 authorized but unissued shares. Preferred stock may be issued from time to time in one or more series, and the Board, without further approval of the stockholders, is authorized to fix the dividend rates and terms, conversion rights, voting rights, redemption rights and terms, liquidation preferences, sinking fund and any other rights, preferences, privileges and restrictions applicable to each series of preferred stock.

4. Commitments and Contingencies

During 2000, the Company fulfilled its international drilling and work unit commitments in Bolivia, Ecuador and Yemen. Through its December 2000 acquisition of Cometra Energy (Canada), Ltd. ("Cometra"), the Company assumed the drilling obligations of Cometra's wholly-owned subsidiary, Cometra Trinidad Limited. These obligations require the acquisition of 15 line kilometers of 2-D seismic, 40 square kilometers of 3-D seismic and drilling of three exploratory wells.

The Company's stock price guarantee issued to Elf in connection with the Company's acquisition of Elf's Ecuador operations in 1998 expired during 2000. The Company was not required to make any additional cash payment or additional stock issuance in fulfillment of this guarantee.

The Company had $8.7 million in letters of credit outstanding at December 31, 2000. These letters of credit relate primarily to various obligations for acquisition and exploration activities in South America and bonding requirements of various state regulatory agencies for oil and gas operations. The Company's availability under its revolving credit facility is reduced by the outstanding letters of credit.

Rent expense was $2.3 million, $1.8 million and $1.2 million for 2000, 1999 and 1998, respectively. The future minimum commitments under long-term, non-cancellable leases for office space are $1.8 million, $1.9 million, $2.0 million, $2.1 million and $3.6 million for the years 2001 through 2005, respectively, with $1.3 million remaining in years thereafter.

On November 5, 1996, the Province of Santa Cruz, Argentina brought suit against the Company's subsidiary Cadipsa S.A. in the Corte Suprema de Justicia de la Nacion (the Supreme Court of Justice of the Argentine Republic, Buenos

Aries, Argentina), Dossier No. s-1451, seeking to recover approximately $10.6 million (which sum includes interest) allegedly due as additional royalties on four concessions granted in 1990 in which the Company currently owns 100 percent working interest. The Company and its predecessors in title have been paying royalties at an eight percent rate; the Province of Santa Cruz claimed the rate should be 12 percent. On May 19, 2000, the Company announced it had received notice of an adverse decision regarding this suit. As a result of the court's decision, the Company has recorded a one-time, after-tax charge to "Other expense" in the second quarter of approximately $25.1 million ($16.3 million after-tax). Further, the Company believes that it is entitled to partial indemnification by a third party with respect to the decision. The pre-tax amount remaining to be paid of $1.6 million is included in "Other payables and accrued liabilities" in the accompanying balance sheet. The impact of the decision on the Company's Argentina production, reserves and present value was not material.

The Company is a defendant in various other lawsuits and is a party in governmental proceedings from time to time arising in the ordinary course of business. In the opinion of management, none of the various other pending lawsuits and proceedings should have a material adverse impact on the Company's financial position or results of operations.

5. Financial Instruments

Price Risk Management

The Company periodically uses hedges (swap agreements) to reduce the impact of oil and natural gas price fluctuations on its operating results and cash flows. These swap agreements typically entitle the Company to receive payments from (or require it to make payments to) the counter parties based upon the differential between a fixed price and a floating price based on a published index. The Company's hedging activities are conducted with major corporations and investment and commercial banks which the Company believes are minimal credit risks. The Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risks. These policies prohibit speculation with derivatives and limit swap agreements to counter parties with appropriate credit standings.

At December 31, 2000, the Company was a party to oil price swap agreements for various periods of 2001 covering 3.5 MMBbls at a weighted average NYMEX reference price of $30.76 per Bbl. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

Fair Value of Financial Instruments

The Company values financial instruments as required by Statement of Financial Accounting Standards No. 107, Disclosures About Fair Value of Financial Instruments. The Company estimates the value of the Notes based on quoted market prices. The Company estimates the value of its other long-term debt based on the estimated borrowing rates currently available to the Company for long-term loans with similar terms and remaining maturities. The estimated fair value of the Company's long-term debt at December 31, 2000 and 1999, was $475.2 million and $621.6 million, respectively, compared with a carrying value of $464.2 million and $625.3 million, respectively.

The fair value of commodity swap agreements is the amount at which they could be settled, based on quoted market prices. The Company was unable to estimate the fair value of the natural gas basis swaps in place at December 31, 1998, as there was no quoted market price available. At December 31, 1999, the Company would have received approximately $700,000 to terminate its oil swap agreements then in place. At December 31, 2000, the Company would have received approximately $16.3 million to terminate its oil swap agreements then in place. The carrying value of other financial instruments approximates fair value because of the short maturity of those instruments.

6. Income Taxes

Income (loss) before income taxes and cumulative effect of change in accounting principle is composed of the following:

(In thousands)	2000	1999	1998
Domestic..............................	$123,951	$33,097	$(122,331)
Foreign...............................	166,324	64,603	(8,898)
	$290,275	$97,700	$(131,229)

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The total provision (benefit) for income taxes consists of the following:

(In thousands)	2000	1999	1998
Current:			
Domestic..................	$ 17,053	$ 1,036	$ (5,324)
Foreign...................	51,805	4,918	1,256
Deferred:			
Domestic..................	32,460	11,730	(43,722)
Foreign...................	(8,358)	6,645	4,226
	$ 92,960	$ 24,329	$ (43,564)

A reconciliation of the U.S. Federal statutory income tax rate to the effective rate is as follows:

	2000	1999
U.S. Federal statutory income tax rate..........................	35.0%	35.0
State income tax..	3.9	3.9
Foreign operations..	(2.8)	(2.9

Effect of conversion of foreign production sharing contracts	4.0)	-
Argentina NOL valuation allowance (reversal)	-	(5.8
Argentina NOL carryforward utilization	-	(5.2
U.S. Federal income tax credits	-	(0.1
Other	(0.1)	-
	32.0%	24.9

The components of the Company's net deferred tax liability as of December 31, 2000 and 1999, are as follows:

(In thousands)	2000
Deferred Tax Assets:	
U.S. Federal and state net operating loss carryforwards	$ 976
U.S. Federal alternative minimum tax credit carryforward	-
Foreign net operating loss carry forwards	16,291
Other temporary book/tax differences	7,832
	25,099
Deferred Tax Liabilities:	
Book/tax differences in property basis	58,057
Other temporary book/tax differences	294
	58,351
Net deferred tax liability	$ 33,252

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Earnings of the Company's foreign subsidiaries are subject to foreign income taxes. No U.S. deferred tax liability will be recognized related to the unremitted earnings of these foreign subsidiaries, as it is the Company's intention, generally, to reinvest such earnings permanently. The Company has a Bolivian income tax net operating loss ("NOL") of approximately $65 million that does not expire and can be used to offset its future income tax liabilities.

The Company fully utilized its $60.0 million U.S. Federal regular tax NOL carryforward and its alternative minimum tax credit carryforward in 2000. The Company also has various state NOL carryforwards which have varying lengths of allowable carryforward periods ranging from five to 20 years and can be used to offset future state taxable income.

7. Segment Information

The Company applies Statement of Financial Accounting Standards No. 131, Disclosures About Segments of an Enterprise and Related Information. The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the exploration and production segment are derived from the production and sale of natural gas and crude oil. Revenues for the gathering segment arise from the transportation and sale of natural gas and crude oil. The gas marketing segment generates revenue by earning fees through the marketing of Company produced gas volumes and the purchase and resale of third party produced gas volumes. The Company evaluates the performance of its operating segments based on operating income.

Operations in the gathering and gas marketing industries are in the United States. The Company operates in the oil and gas exploration and production industry in the United States, South America, Yemen and, beginning in December 2000, Canada. Summarized financial information for the Company's reportable segments is shown on the following page.

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VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Exploration and Production				
	U.S.	Argentina	Other Foreign	Gathering	Gas Marketing
2000 (in thousands)					
Revenues from external customers........	$346,574	$ 256,234	$ 52,429	$ 19,998	$128,836
Intersegment revenues..................	-	-	-	2,080	2,372
Depreciation, depletion and amortization expense...........	53,184	33,077	10,074	1,567	-
Impairment of oil and gas properties....	225	-	-	-	-
Operating income (loss)................	192,508	170,301	10,988	1,380	5,049
Total assets...........................	524,588	459,219	257,926	13,479	35,977
Capital investments....................	64,125	92,885	100,663	299	-
Long-lived assets......................	477,198	401,702	215,352	5,862	-
1999 (in thousands)					
Revenues from external customers........	$275,486	$ 142,374	$ 16,103	$ 6,955	$ 60,275
Intersegment revenues..................	-	-	-	1,350	1,285
Depreciation, depletion and amortization expense...........	70,520	29,496	3,703	1,400	-
Impairment of oil and gas properties....	3,306	-	-	-	-
Operating income (loss)................	112,902	77,033	665	402	2,725
Total assets...........................	520,443	379,099	174,009	6,372	6,601
Capital investments....................	51,571	131,551	54,362	680	-
Long-lived assets......................	476,153	342,179	144,673	3,629	-
1998 (in thousands)					
Revenues from external customers........	$195,060	$ 68,630	$ 7,359	$ 7,741	$ 54,108
Intersegment revenues..................	-	-	-	884	1,466
Depreciation, depletion and					

amortization expense...........	75,479	26,610	2,968	1,693	-
Impairment of oil and gas properties....	70,913	-	-	-	-
Operating income (loss)................	(66,275)	12,282	(2,098)	(210)	2,548
Total assets...........................	569,560	256,525	113,956	7,500	8,735
Capital investments....................	177,970	44,592	63,798	1,831	-
Long-lived assets......................	536,885	245,831	100,441	4,350	-

Intersegment sales are priced in accordance with terms of existing contracts and current market conditions. Capital investments include expensed exploratory costs. Corporate general and administrative costs and interest costs are not allocated to segments.

During 2000, sales to two crude oil purchasers of the exploration and production segment represented approximately 17 percent and 12 percent, respectively, of the Company's total revenues (exclusive of eliminations of intersegment sales and the impact of hedges). During 1999, sales to two crude oil purchasers of the exploration and production segment represented approximately 14 percent and 11 percent, respectively, of the Company's total revenues (exclusive of eliminations of intersegment sales, the impact of hedges and $55.0 million of net proceeds from the sales of oil and gas properties). The Company had no single purchaser to which sales of any segment in 1998 exceeded 10 percent of the Company's total revenues.

8. Detail of Prepaids and Other Current Assets

(In thousands)	2000	1999
Property divestiture proceeds receivable..........	$ -	$ 9,704
Other prepaids and current assets.................	13,946	9,405
	$13,946	$19,109

9. Quarterly Results (Unaudited)

The following is a summary of the quarterly results of operations for the years ended December 31, 2000 and 1999. The four quarters of 1999 and the first three quarters of 2000 have been restated to reflect a reclassification of transportation and storage charges from revenues to lease operating expense and the first three quarters of 2000 have also been restated to reflect a change in accounting principle related to inventory valuation.

(In thousands, except per share amounts)	Quart	
	Mar. 31	Jun. 30
2000		
Revenues...	$162,391	$156,266(
Operating income.....................................	73,701	53,783(

Cumulative effect of change in accounting principle......	(1,422)	-
Provision for income taxes..............................	20,580	14,800
Net income..	38,284(a)	27,059(
Income per share:		
Basic..	.61(a)	.43(
Diluted..	.60(a)	.42(
1999		

Revenues..	$ 67,388	$ 93,798
Operating income (loss).................................	(14,856)	19,026
Provision (benefit) for income taxes....................	(11,295)	(733)
Net income (loss).......................................	(18,121)	5,183
Income (loss) per share:		
Basic...	(.34)	.10
Diluted...	(.34)	.09

(a) Net income for the quarter ended March 31, 2000, includes the cumulative effect of a change in accounting principle, net of tax, of $1.4 million, or two cents per share.

(b) The quarter ended June 30, 2000, includes a reduction in revenues of $25.1 million ($16.3 million net of tax, or 25 cents per share), related to a non-recurring charge resulting from an Argentina litigation loss related to a royalty dispute.

(c) Revenues and operating income for the quarter ended December 31, 1999, were increased by $47.3 million related to gains recognized on the sale of certain oil and gas properties. The impact of this item increased net income for the quarter ended December 31, 1999, by $28.9 million or 46 cents per basic share and 45 cents per diluted share.

10. Supplementary Financial Information for Oil and Gas Producing Activities

Results of Operations from Oil and Gas Producing Activities

The following sets forth certain information with respect to the Company's results of operations from oil and gas producing activities for the years ended December 31, 2000, 1999 and 1998. The Company began operations in Ecuador in November 1998 and Canada in December 2000.

	2000			
(In thousands)	U.S.	Argentina	Bolivia	Ecuador
Revenues..	$348,305	$281,334	$19,535	$30,613
Production (lifting) costs......................	96,386	52,856	3,777	6,116
Exploration costs...............................	4,271	-	12,133	2,526
Impairment of proved properties.................	225	-	-	-
Depreciation, depletion and amortization.........	53,184	33,077	7,421	2,067
Results of operations before income taxes........	194,239	195,401	(3,796)	19,904

Income tax expense (benefit)	75,559	68,390	(949)	4,976
Results of operations (excluding corporate overhead and interest costs)	$118,680	$127,011	$(2,847)	$14,928

	1999			
(In thousands)	U.S.	Argentina	Bolivia	Ecuador
Revenues	$220,495	$142,374	$ 5,786	$10,316
Production (lifting) costs	80,516	35,845	3,024	2,279
Exploration costs	8,242	-	1,671	-
Impairment of proved properties	3,306	-	-	-
Depreciation, depletion and amortization	70,520	29,496	2,380	1,323
Results of operations before income taxes	57,911	77,033	(1,289)	6,714
Income tax expense (benefit)	22,527	16,695	(438)	-
Results of operations (excluding corporate overhead and interest costs)	$ 35,384	$ 60,338	$ (851)	$ 6,714

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	1998			
(In thousands)	U.S.	Argentina	Bolivia	Othe
Revenues	$ 195,060	$ 68,630	$ 6,789	$ 5
Production (lifting) costs	94,332	29,548	2,879	3
Exploration costs	20,610	191	2,255	1,0
Impairment of proved properties	70,913	-	-	
Depreciation, depletion and amortization	75,479	26,610	2,858	1
Results of operations before income taxes	(66,274)	12,281	(1,203)	(8
Income tax expense (benefit)	(25,781)	4,299	(423)	(3
Results of operations (excluding corporate overhead and interest costs)	$ (40,493)	$ 7,982	$ (780)	$ (5

Capitalized Costs and Costs Incurred Relating to Oil and Gas Producing Activities

The Company's net investment in oil and gas properties at December 31, 2000 and 1999, was as follows:

(In thousands)	2000 U.S.	Canada	Argentina	Bolivia	Ecuado
Unproved properties not being amortized.........	$ 20,446	$ 3,922	$ -	$ -	$
Proved properties being amortized............	949,901	49,981	533,727	113,399	45,08
Total capitalized costs...	970,347	53,903	533,727	113,399	45,08
Less accumulated depreciation, depletion and amortization..	493,149	596	132,025	15,873	3,42
Net capitalized costs.....	$ 477,198	$ 53,307	$ 401,702	$ 97,526	$ 41,65

(In thousands)	1999 U.S.	Argentina	Bolivia	Ecuado
Unproved properties not being amortized........	$ 15,867	$ -	$ -	$ 97
Proved properties being amortized.............	910,357	440,842	96,793	50,30
Total capitalized costs....................	926,224	440,842	96,793	51,28
Less accumulated depreciation, depletion and amortization.................	455,158	98,663	8,501	1,43
Net capitalized costs......................	$ 471,066	$ 342,179	$ 88,292	$ 49,85

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The following sets forth certain information with respect to costs incurred (exclusive of general support facilities) in the Company's oil and gas activities during 2000, 1999 and 1998:

(In thousands)	2000 U.S.	Canada	Argentina	Bolivia	Ecuad
Acquisitions:					
Undeveloped properties.......................	$ 2,176	$ 3,614	$ -	$ 225	$
Producing properties.........................	6,035	47,927	43,428	-	(5,
Exploratory..................................	23,841	212	-	27,532	1,
Development..................................	32,072	1,035	49,457	983	

Total costs incurred	$64,124	$52,788	$92,885	$28,740	$(3,

	1999				
(In thousands)	U.S.	Argentina	Bolivia	Ecuador	Othe
Acquisitions:					
Undeveloped properties	$ 510	$ -	$ -	$ -	$ 6
Producing properties	31,662	121,015	-	14,110	
Exploratory	10,316	-	27,834	-	6,8
Development	9,083	10,536	2,955	1,981	
Total costs incurred	$51,571	$131,551	$30,789	$16,091	$7,4

	1998				
(In thousands)	U.S.	Argentina	Bolivia	Ecuador	Ot
Acquisitions:					
Undeveloped properties	$ 6,460	$ -	$ -	$ 101	$ 4
Producing properties	70,805	-	-	34,218	
Exploratory	49,952	1,416	10,324	396	
Development	50,753	43,176	13,949	-	
Total costs incurred	$ 177,970	$ 44,592	$ 24,273	$ 34,715	$ 4

Estimated Quantities of Proved Oil and Gas Reserves (Unaudited)

Proved oil and gas 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 reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. The following is an analysis of the Company's proved oil and gas reserves located in the United States, Argentina and Ecuador as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc., in Bolivia as estimated by the independent petroleum consultants of DeGolyer and MacNaughton, and in Canada as estimated by the Company.

	Oil (MBbls)			
	U.S.	Canada	Argentina	Bol
Proved reserves at December 31, 1997	99,934	-	81,651	6
Revisions of previous estimates	(38,473)	-	(4,579)	
Extensions, discoveries and other additions	306	-	4,091	2
Production	(9,912)	-	(6,322)	
Purchase of reserves-in-place	5,452	-	-	
Sales of reserves-in-place	(100)	-	-	
Proved reserves at December 31, 1998	57,207	-	74,841	8
Revisions of previous estimates	52,684	-	24,496	(1
Extensions, discoveries and other additions	110	-	-	1
Production	(8,643)	-	(7,560)	
Purchase of reserves-in-place	10,343	-	44,694	
Sales of reserves-in-place	(1,259)	-	-	
Proved reserves at December 31, 1999	110,442	-	136,471	8
Revisions of previous estimates	397	-	18,501	(1
Extensions, discoveries and other additions	329	-	-	
Production	(9,044)	(19)	(9,406)	
Purchase of reserves-in-place	447	2,407	11,970	
Sales of reserves-in-place	(235)	-	-	
Proved reserves at December 31, 2000	102,336	2,388	157,536	6
Proved developed oil reserves at:				
December 31, 1998	51,481	-	47,167	4
December 31, 1999	94,722	-	90,125	6
December 31, 2000	90,774	1,558	94,191	5

	Gas (MMcf)			
	U.S.	Canada	Argentina	Bo
Proved reserves at December 31, 1997	360,847	-	-	1

Revisions of previous estimates	(11,252)	-	12,024	1
Extensions, discoveries and other additions	28,345	-	-	1
Production	(42,176)	-	-	
Purchase of reserves-in-place	53,027	-	-	
Sales of reserves-in-place	(3,279)	-	-	
Proved reserves at December 31, 1998	385,512	-	12,024	4
Revisions of previous estimates	32,505	-	25,222	
Extensions, discoveries and other additions	1,844	-	-	
Production	(39,150)	-	(4,682)	
Purchase of reserves-in-place	14,947	-	81,072	
Sales of reserves-in-place	(34,633)	-	-	
Proved reserves at December 31, 1999	361,025	-	113,636	5
Revisions of previous estimates	39,123	-	13,990	(
Extensions, discoveries and other additions	34,990	-	-	
Production	(35,764)	(312)	(8,705)	
Purchase of reserves-in-place	1,376	39,790	2,278	
Sales of reserves-in-place	(2,078)	-	-	
Proved reserves at December 31, 2000	398,672	39,478	121,199	4
Proved developed gas reserves at:				
December 31, 1998	330,371	-	12,024	2
December 31, 1999	302,444	-	92,696	4
December 31, 2000	333,453	33,405	41,822	3

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves ("Standardized Measure") is a disclosure requirement under Statement of Financial Accounting Standards No. 69. The Standardized Measure does not purport to present the fair market value of proved oil and gas reserves. This would require consideration of expected future economic and operating conditions which are not taken into account in calculating the Standardized Measure.

Under the Standardized Measure, future cash inflows were estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows were reduced by estimated future production, development and abandonment costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved oil and gas properties. Tax credits and permanent differences were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

Set forth below is the Standardized Measure relating to proved oil and gas reserves at December 31, 2000 and 1999:

	2000			
(In thousands)	U.S.	Canada	Argentina	Bolivia
Future cash inflows......................	$ 6,484,886	$ 355,171	$ 3,757,493	$ 572,917
Future production costs..................	1,656,100	45,558	1,221,302	48,796
Future development and abandonment costs.......................	221,193	12,696	281,555	51,900
Future net cash inflows before income tax expense......................	4,607,593	296,917	2,254,636	472,221
Future income tax expense................	1,675,283	110,332	665,236	97,473
Future net cash flows....................	2,932,310	186,585	1,589,400	374,748
10 percent annual discount for estimated timing of cash flows..........	1,366,053	39,435	682,161	200,329
Standardized Measure of discounted future net cash flows..................	$ 1,566,257	$ 147,150	$ 907,239	$ 174,419

	1999			
(In thousands)	U.S.	Argentina	Bolivia	Ecuador
Future cash inflows........................	$ 3,287,165	$ 3,326,461	$ 713,314	$ 1,012,
Future production costs....................	1,265,432	947,564	51,564	235,
Future development and abandonment costs.........................	188,019	195,729	47,050	140,
Future net cash inflows before income tax expense........................	1,833,714	2,183,168	614,700	636,
Future income tax expense..................	538,602	654,633	189,054	204,

Future net cash flows......................	1,295,112	1,528,535	425,646	431,
10 percent annual discount for estimated timing of cash flows............	475,281	583,187	222,991	151,
Standardized Measure of discounted future net cash flows.....................	$ 819,831	$ 945,348	$ 202,655	$ 279,

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Unaudited)

The following is an analysis of the changes in the Standardized Measure during 2000, 1999 and 1998:

(In thousands)	2000	1999
Standardized Measure - beginning of year............................	$2,247,237	$ 648,222
Increases (decreases) -		
Sales, net of production costs.....................................	(522,545)	(255,260
Net change in sales prices, net of production costs.................	1,131,540	1,218,764
Discoveries and extensions, net of related future development and production costs..........................	148,727	62,427
Changes in estimated future development costs......................	(87,127)	(52,195
Development costs incurred...	93,276	21,472
Revisions of previous quantity estimates...........................	267,178	732,703
Accretion of discount..	298,963	70,357
Net change in income taxes...	(645,108)	(687,057
Purchase of reserves-in-place......................................	278,740	496,237
Sales of reserves-in-place...	(4,787)	(54,135
Timing of production of reserves and other.........................	(254,973)	45,702
Standardized Measure - end of year.................................	$2,951,121	$2,247,237

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INDEX TO EXHIBITS

The following documents are included as exhibits to this Form 10-K. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, such exhibit is filed herewith.

Exhibit Number	Description
3.1	Restated Certificate of Incorporation, as amended, of the Company (Filed as Exhibit 3.2 to the Company's report on Form 10-Q for the quarter ended June 30, 2000, filed August 11, 2000).
3.2	Restated By-laws of the Company (Filed as Exhibit 3.2 to the Company's Registration Statement on Form S-1, Registration No. 33-35289 (the "S-1 Registration Statement")).

4.1	Form of stock certificate for Common Stock, par value $.005 per share (Filed as Exhibit 4.1 to the S-1 Registration Statement).
4.2	Indenture dated as of December 20, 1995, between The Chase Manhattan Bank (formerly Chemical Bank), as Trustee, and the Company (Filed as Exhibit 99.1 to the Company's report on Form 8-K filed January 16, 1996).
4.3	Indenture dated as of February 5, 1997, between The Chase Manhattan Bank, as Trustee, and the Company (Filed as Exhibit 4.3 to the Company's report on Form 10-K for the year ended December 31, 1996, filed March 27, 1997).
4.4	Indenture dated as of January 26, 1999, between The Chase Manhattan Bank, as Trustee, and the Company (Filed as Exhibit 4.4 to the Company's report on Form 10-K for the year ended December 31, 1998, filed March 12, 1999).
4.5	Rights Agreement, dated March 16, 1999, between the Company and ChaseMellon Shareholder Services, L.L.C., as Rights Agent (Filed as Exhibit 4.1 to the Company's Registration Statement on Form 8-A, filed March 22, 1999).
4.6	Certificate of Designation of Series A Junior Participating Preferred Stock of the Company (Filed as Exhibit 3.3 to the Company's Registration Statement on Form S-3, Registration No. 333-77619).
10.1*	Employment and Noncompetition Agreement dated January 7, 1987, between the Company and Charles C. Stephenson, Jr. (Filed as Exhibit 10.19 to the S-1 Registration Statement).
10.2*	Form of Indemnification Agreement between the Company and certain of its officers and directors (Filed as Exhibit 10.23 to the S-1 Registration Statement).
10.3*	Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 4(d) to the Company's Registration Statement on Form S-8, Registration No. 33-37505).
10.4*	Amendment No. 1 to Vintage Petroleum, Inc. 1990 Stock Plan, effective January 1, 1991 (Filed as Exhibit 10.15 to the Company's report on Form 10-K for the year ended December 31, 1991, filed March 30, 1992).
10.5*	Amendment No. 2 to Vintage Petroleum, Inc. 1990 Stock Plan dated February 24, 1994 (Filed as Exhibit 10.15 to the Company's report on Form 10-K for the year ended December 31, 1993, filed March 29, 1994).

10.6*	Amendment No. 3 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 15, 1996 (Filed as Exhibit A to the Company's Proxy Statement for Annual Meeting of Stockholders dated April 1, 1996).
10.7*	Amendment No. 4 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 11, 1998 (Filed as Exhibit A to the Company's Proxy Statement for Annual Meeting of Stockholders dated March 31,

1998).

10.8* Amendment No. 5 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 16, 1999 (Filed as Exhibit A to the Company's Proxy Statement for Annual Meeting of Stockholders dated March 31, 1999).

10.9* Amendment No. 6 to Vintage Petroleum, Inc. 1990 Stock Plan dated March 17, 2000 (Filed as Exhibit A to the Company's Proxy Statement for Annual Meeting of Stockholders dated March 30, 2000).

10.10* Vintage Petroleum, Inc. 401(k) Plan (Filed as Exhibit 4(C) to the Company's Registration Statement on Form S-8, Registration No. 33-55706).

10.11* Vintage Petroleum, Inc. Non-Management Director Stock Option Plan (Filed as Exhibit 10.18 to the Company's report on Form 10-K for the year ended December 31, 1992, filed March 31, 1993 (the "1992 Form 10-K")).

10.12* Form of Incentive Stock Option Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.20 to the Company's report on Form 10-K for the year ended December 31, 1990, filed April 1, 1991).

10.13* Form of Non-Qualified Stock Option Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.20 to the 1992 Form 10-K).

10.14* Form of Non-Qualified Stock Option Agreement for non-employee directors under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.13 to the Company's report on Form 10-K for the year ended December 31, 1999, filed March 13, 2000).

10.15 Second Amended and Restated Credit Agreement dated as of November 30, 2000, among the Company, as borrower, and certain commercial lending institutions, as lenders, Bank of Montreal, as administrative agent, Bank of America, N.A., as syndication agent, Societe Generale, Southwest Agency, as documentation agent, and ABN AMRO Bank, N.V., as managing agent.

21. Subsidiaries of the Company.

23.1 Consent of Arthur Andersen LLP.

23.2 Consent of Netherland, Sewell & Associates, Inc.

23.3 Consent of DeGolyer and MacNaughton.

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* Management contract or compensatory plan or arrangement.