VINTAGE PETROLEUM INC
Form 10-K
March 20, 2002

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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, 2001

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 March 15, 2002, 63,081,322 shares of the Registrant's Common

Stock were outstanding, and the aggregate market value of the Common Stock held by non-affiliates was approximately $628,176,000.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement for the Annual Meeting of Stockholders to be held May 14, 2002, are incorporated by reference into Part III of this Form 10-K.

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VINTAGE PETROLEUM, INC.
FORM 10-K
YEAR ENDED DECEMBER 31, 2001
TABLE OF CONTENTS

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(Degree) Fahrenheit. Equivalent Bbls of oil and equivalent Mcf of gas 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" 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:

- amounts 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:

- 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;
- actions taken and to be taken by Argentina as a result of its economic instability;
- continued availability of capital and financing;
- general economic, market or business conditions;
- acquisitions 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 favorable prices, its technical expertise and its low cost structure.

At December 31, 2001, the Company owned and operated producing properties in nine states in the U.S., with its domestic proved reserves located primarily in four core areas: Gulf Coast, East Texas, Mid-Continent and West Coast. During 2001, the Company significantly expanded its North American operations in Canada through the acquisition of 100 percent of Genesis Exploration Ltd. ("Genesis," now Vintage Petroleum Canada, Inc.). See "Acquisitions." Additionally, the Company has international core areas located in Argentina, Bolivia and Ecuador. In Argentina, the Company owns 20 oil concessions, 16 of which are operated by the Company. Fourteen of these operated concessions are located in the south flank of the San Jorge Basin in southern Argentina. The Company recently expanded its Argentina core area into the Cuyo Basin in western Argentina with the purchase of the Piedras Colorados and Cachueta concessions in 2000, and the purchase of the La Ventana and Rio Tunuyan concessions in 2001. See "Acquisitions." In Bolivia, the Company owns and operates three blocks in the Chaco Plains area of southern Bolivia and the Naranjillos concession located in the Santa Cruz Province. The Company also currently operates three blocks in the Oriente Basin in Ecuador and this area provides substantial undeveloped acreage which the Company believes has significant development and exploration potential.

As of December 31, 2001, the Company owned interests in 3,058 gross (2,591 net) productive wells in the U.S., of which approximately 89 percent are operated by the Company, 808 gross (446 net) productive wells in Canada, of which approximately 55 percent are operated by the Company, 1,484 gross (1,329 net) productive wells in Argentina, of which approximately 83 percent are operated by the Company, 15 gross (14 net) productive wells in Bolivia, all of which are operated by the Company, nine gross (seven net) productive wells in Ecuador, all of which are operated by the Company, and two gross (one net) productive wells in Trinidad, both of which are operated by the Company. As of December 31, 2001, the Company's properties had proved reserves of 535.0 MMBOE, comprised of 332.3 MMBbls of oil and 1.2 Tcf of gas, with a present value of estimated future net revenues before income taxes (utilizing a 10 percent discount rate) of $1.9 billion and a standardized measure of discounted future net cash flows of $1.4 billion. From the first quarter of 1999 through the fourth quarter of 2001, the Company increased its average net daily production from 42,100 Bbls of oil to 64,300 Bbls of oil and from 120,900 Mcf of gas to 240,300 Mcf of gas.

Financial information relating to the Company's industry segments is set forth in Note 8 "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 with significant upside potential at favorable prices, (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 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) favorable 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, large independent and national oil companies has afforded in the past, and should afford in the future, favorable 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, 1999, through December 31, 2001, the Company has spent $865.5 million acquiring 190.3 MMBOE of proved oil and gas reserves at an average acquisition cost of $4.55 per BOE. The Company replaced, through acquisitions, approximately 215 percent of its production of 88.3 MMBOE during the same period. During 2001, the Company spent $607.2 million acquiring 74.1 MMBOE of proved oil and gas reserves at an average acquisition cost of $8.19 per BOE, reflecting the higher cost of the Company's acquisition of Genesis. The 2001 acquisitions replaced approximately 214 percent of the Company's production of 34.6 MMBOE during 2001. For additional information, see "Acquisitions." 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, 1999, through December 31, 2001, the Company spent approximately $277.7 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, 2001, the Company succeeded in adding 61.9 MMBOE to proved reserves, replacing approximately 70 percent of production during the same period at a cost of $4.49 per BOE. During 2001, the Company spent $168.8 million on exploitation and development activities and added 25.0 MMBOE to proved reserves, replacing approximately 72 percent of 2001 production at a cost of $6.75 per BOE. For additional information, see "Exploitation and Development." The Company continues to maintain an extensive inventory of exploitation and development opportunities. Due to the anticipated lower oil and gas price environment for 2002, as compared to 2001, and the economic instability in Argentina (see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in this Form 10-K), the Company has decreased its budgeted level of spending to $105 million in 2002 on exploitation and development projects, primarily in North America and Ecuador.

- Exploration. The Company's overall exploration strategy balances high potential international prospects with lower risk drilling in known formations in North America 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 data, which further reduces the cost of its exploration program by increasing its success. From January 1, 1999, through December 31, 2001, the Company spent approximately $189.8 million on exploration activities, excluding $53.6 million to acquire the large acreage inventory of Genesis in May 2001. During this period, the Company drilled 92 gross (63 net) exploration wells, of which approximately 62 percent were productive. As a result of all of the Company's exploration activities during the three-year period ended December 31, 2001, the Company succeeded in adding 44.1 MMBOE to proved reserves, replacing approximately 50 percent of production during this period at a cost of $4.31 per BOE. For additional information, see "Exploration." The Company's exploration activities in 2001 were focused on its core areas in the U.S. and Canada and additionally in Trinidad and Yemen. Due to the anticipated lower oil and gas price environment for 2002, as compared to 2001, the Company anticipates reduced 2002 spending of approximately $39 million on exploration projects, primarily in North America and Yemen.

- 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 two Rule 144A private debt offerings, all of which have provided the Company with aggregate net proceeds of approximately $843 million. From December 31, 2000, to May 2, 2001, the Company's net long-term debt-to-book capitalization ratio increased from 41.6 percent to 59.1 percent, primarily as a result of the acquisition of Genesis. Since May 2, 2001, the Company applied cash flow over non-acquisition capital expenditures and proceeds from the sale of non-strategic oil and gas properties to reduce outstanding long-term debt, lowering its net long-term debt-to-book capitalization ratio to 57.7 percent at December 31, 2001. The Company plans to further reduce this ratio during 2002. It has restricted its planned non-acquisition capital expenditure level and may consider additional property sales and other measures, including consideration of the method of funding future acquisitions, to achieve this goal. Internally generated cash flow, the borrowing capacity under its revolving credit facility and its ability to adjust its level of capital expenditures are the Company's major sources of liquidity. For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity" included elsewhere in this Form 10-K.

Acquisitions

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, large independent and national oil companies has afforded in recent years, and should afford in the future, favorable opportunities to purchase domestic and international producing properties.

3

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 U.S., 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 and Trinidad with the purchase of 100 percent of Cometra Energy (Canada), Ltd. ("Cometra," now Vintage Energy (Canada), Ltd.), a privately-held Canadian company. The Company significantly expanded its Canadian operations in 2001 with the purchase of 100 percent of Genesis, a publicly-traded Canadian company. The Company also extended its Argentina operations in 2000 with its acquisition of two concessions from Perez Companc and in 2001 with its purchase of the La Ventana and Rio Tunuyan concessions from Shell C.A.P.S.A., a wholly-owned affiliate of Royal Dutch Shell. 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, 1999, through December 31, 2001, the Company made oil and gas reserve acquisitions with costs totaling approximately $865.5 million. As a result of these acquisitions, the Company acquired approximately 190.3 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 B When Acqui
	(In thousands)				

North America Acquisitions:					
1999	$ 31,662	10,343	14,947	12,834	$ 2
2000	53,962	2,854	41,166	9,715	5
2001	564,950	27,493	207,701	62,110	9
Total North America Acquisitions ..	650,574	40,690	263,814	84,659	7
South America Acquisitions:					
1999	135,125	67,733	81,072	81,245	1
2000	37,486	11,970	2,278	12,350	3
2001	42,267	11,724	1,636	11,997	3
Total South America Acquisitions ..	214,878	91,427	84,986	105,592	2
Total Acquisitions	$ 865,452	132,117	348,800	190,251	$ 4

The Company estimates that 74.1 MMBOE of proved reserves, as of the various acquisition dates, were acquired in 2001 for an aggregate cost attributable to oil and gas reserves of $607.2 million, resulting in an average cost of $8.19 per BOE. The average cost per BOE over the three-year period ended December 31, 2001, is $4.55 and the cost since the Company's inception is $3.49 per BOE.

The following is a brief discussion of the significant acquisitions in 2001:

Genesis Exploration Ltd. (Canada). In May 2001, the Company acquired 100 percent of the outstanding common stock of Genesis for total consideration of $617 million, including transaction costs and the assumption of the estimated net indebtedness of Genesis at closing. Approximately $562.4 of the purchase price was allocated to oil and gas reserves. The cash portion of the acquisition price was paid through advances under the Company's revolving credit facility and cash on hand.

4

The Company acquired 62.1 MMBOE of proved reserves in the transaction with Genesis consisting of approximately 27.5 MMBbls of oil and 207.7 Bcf of gas. Proved undeveloped reserves of oil and gas accounted for approximately 33 percent of total proved BOE of reserves. In addition, the Company acquired a significant amount of probable reserves, representing upside potential which may be realized through its 2002 work program and beyond. The reserves acquired in the Genesis transaction are located primarily in the provinces of Alberta and Saskatchewan with a significant exploration exposure in the Northwest Territories.

In addition to reserves, the Company acquired over one million net undeveloped acres located in Alberta and Saskatchewan with a significant portion, aggregating to 440,000 net acres, in the Northwest Territories. Also, the Genesis acquisition brought with it over 600 square miles of 3-D seismic data and over 15,000 miles of 2-D seismic data. The Company estimates the acquisition cost of proved reserves was approximately $9.06 per BOE, exclusive of $54 million allocated to undeveloped acreage. At the time of acquisition, net daily production from the Genesis properties was approximately 17,800 BOE, composed of approximately 71 MMcf of gas and 6,000 Bbls of oil.

With the Genesis acquisition closely following the 2000 acquisition of Cometra, the Company has not only added significant reserves and production to a new core area, but also enhanced its ability to grow from its expanded North American exploration program. At the same time, this acquisition accomplished a better balance of the Company's geographical mix of production and proved oil and gas reserves between North America and other international areas.

Cuyo Basin Properties (Argentina). In September 2001, the Company acquired 100 percent of the outstanding common stock of a privately-held Argentine company (now Vintage Petroleum Argentina S.A.) that held concessions in the Cuyo Basin of western Argentina. Subsequently, Vintage Petroleum Argentina S.A. purchased certain non-operated interests in the La Ventana and Rio Tunuyan Blocks in the Cuyo Basin. Total consideration for these transactions was approximately $66.8 million, including transaction costs, and was funded through advances under the Company's revolving credit facility. Approximately $42.3 million of the total purchase price was allocated to oil and gas reserves.

These acquisitions added approximately 12.0 MMBOE of proved reserves, consisting of 11.7 MMBbls of oil and 1.6 Bcf of gas, and net daily production at the time of acquisition of approximately 3,200 Bbls of oil and 500 Mcf of gas. In addition to the producing concessions it now owns, Vintage Petroleum Argentina S.A. had an Argentine income tax net operating loss carryforward at December 31, 2001, of approximately 91 million pesos ($55 million) that expires in varying annual amounts over a five-year period beginning in 2002 and can be used to offset future income tax liabilities.

These acquisitions expanded the Company's presence in the western basins of Argentina, which the Company entered in 2000. One exploration well and one development well have been drilled in the La Ventana concession since the acquisition. The exploration well is currently producing at a daily rate of over 450 gross Bbls (120 net Bbls) of oil per day with several potential offset locations identified.

Divestitures

During 2001, the Company continued its divestiture program designed to sell properties in the U.S. that were either marginally economical or non-strategic to the Company's areas of operation. Net proceeds of $47.1 million from the property sales were achieved primarily through public auctions held during the fourth quarter of 2001. These sales resulted in $26.9 million in gains ($16.7 million after tax), which were included in the Company's 2001 operating results.

Through these sales of 780 wells and over 600 leases in 85 fields, the Company significantly reduced its domestic well and lease count while reducing net domestic production by only six percent, and total net production by three percent. Combined, the Company estimates that the properties sold accounted for proved reserves of 5.7 MMBbls of oil and 27.8 Bcf of gas as of the closing dates of these sales, which represents approximately seven percent of the Company's U.S. proved reserves and two percent of the Company's total proved reserves at December 31, 2001. Net daily production during 2001 from the properties sold averaged approximately 1,330 Bbls of oil and 7,650 Mcf of gas. Divesting of these lower-tier assets, which have average operating costs in excess of $10.00 per BOE, will allow the Company to focus more intently on its remaining high-graded properties and new areas for future growth.

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 these efforts, as well as the effect of period to period changes in year end oil and gas prices and other items, are reflected in revisions to reserves. During the three-year period ended December 31, 2001, net revisions to reserves (excluding the 35.3 MMBOE positive impact of price changes and a 10.9 MMBOE upward revision of proved reserves resulting from the 2001 devaluation of the Argentine peso) totaled 61.9 MMBOE, replacing approximately 70 percent of the Company's production during the same period at a cost of $4.49 per BOE. During 2001, net revisions to reserves (excluding the 40.1 MMBOE negative impact of lower year-end 2001 oil and gas prices and a 10.9 MMBOE upward revision to proved reserves resulting from the devaluation of the Argentine peso) totaled 25.0 MMBOE, replacing approximately 72 percent of the Company's production of 34.6 MMBOE at a cost of $6.75 per BOE.

As a result of stronger oil and gas prices in the first half of 2001 and activity in the Company's new Canadian operations, the Company spent $62.0 million on workovers, recompletion operations and other projects during 2001, significantly higher than 2000. A measure of the overall success of the Company's recompletion and workover operations during 2001 (excluding minor equipment repair and replacement) was that improved production or operating efficiencies were achieved from approximately 79 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 2001, the Company participated in the drilling of 142 gross (119 net) development wells, of which 132 gross (110 net) were productive. At December 31, 2001, the Company's proved reserves included approximately 144 development or infill drilling locations on its U.S. acreage, 82 locations on its Canada acreage, 331 locations on its Argentina acreage, 43 locations on its Ecuador acreage, 16 locations on its Bolivia acreage and three locations on its Trinidad 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 development and infill drilling capital expenditures for 2001, spending an aggregate of $96.2 million, including approximately $13.1 million in the U.S., $21.4 million in Canada, $56.7 million in Argentina and $5.0 million in Ecuador. The Company also spent approximately $10.6 million on the acquisition of development seismic data and other development activities in 2001. As a result of lower anticipated oil and gas prices for 2002, compared to 2001, and the economic instability in Argentina (see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in this Form 10-K), the Company has decreased its 2002 capital budget for all exploitation and development work from $168.8 million in 2001 to $105 million, with spending primarily concentrated in North America and Ecuador.

Exploitation and development activities for 2001 were concentrated mainly in the U.S., Canada and Argentina core areas of the Company. The following is a brief description of significant developments in the Company's recent exploitation and development activities:

United States. The Company's U.S. exploitation program for 2001 included the drilling of 18 gross (nine net) development wells, of which 16 gross (seven net), or 89 percent, were successful. The Stagecoach area in southern Oklahoma was a focus of the Company's U.S. development drilling activities in 2001. Eight gross (four net) successful development wells were drilled in this area in 2001, along with seven gross (three net) exploratory wells, five gross (two net) of which were successful. As a result, the play has been extended both in area and into deeper producing horizons previously untested, setting the stage for continued drilling activity in the next several years. In 2001, the Company also continued its horizontal infill development program in the Luling field in south central Texas, where it drilled a total of five wells. These five wells had a combined initial gross daily production rate of 790 Bbls (700 Bbls net).

The Company's 2001 U.S. exploitation program also included 140 workovers and recompletions, of which 103 gross (97 net) were successful for a 74 percent success rate. Three fields with significant workover activity in 2001 were Main Pass 116, West Ranch and Darst Creek. Two workovers were completed in the Main Pass 116 field, located in shallow federal waters, increasing gross daily gas production by 6.4 MMcf (5.3 MMcf net) through recompletions.

The Company implemented a significant gas reservoir de-watering project in the West Ranch field in south central Texas, with 21 wells adding gross daily production of 3.3 MMcf (2.8 MMcf net) of gas and 210 Bbls (184 Bbls net) of oil. Response from this project is continuing to improve as reservoir pressure is drawn down, liberating previously unrecoverable trapped gas.

The Company's 2002 exploitation and development budget includes $19 million targeted towards U.S. projects. These projects will focus primarily on development drilling, workovers and production enhancement and maintenance projects.

Canada. The Company's exploitation activity in Canada was significant in 2001 as a result of the acquisition of Genesis and Cometra. The Company drilled 54 gross (40 net) development wells in 2001, of which 47 gross (33 net), or 87 percent, were successful. Development drilling in 2001 focused on the Sturgeon Lake, Grouard and West Central operating areas.

Wells in the Sturgeon Lake area target shallow, by-passed gas pays in the Cretaceous section and attic oil accumulations in Devonian reef structures identified and exploited by the application of 3-D seismic data and horizontal drilling. Two significant extensional wells, the South Sturgeon Lake 3-21 and the South Sturgeon Lake 10-27, confirmed new reserve accumulations in the third quarter of 2001. Offsets to both discoveries are anticipated in early 2002. In the fourth quarter of 2001, the Company successfully extended the Banff formation play in the Kakut area of Sturgeon Lake. The Puskawaskau 1-20 was drilled to a total depth of 7,550 feet and tested at a net rate of 1.0 MMcf per day. Installation of compression during the first quarter of 2002 is expected to increase net production to approximately 2.3 MMcf per day. Two pool extension wells are planned in the Kakut area during 2002. Activity in the West Central operating area focused on gas opportunities targeting the Devonian, Mississippian and Triassic pay sections. Fifteen gross (nine net) successful wells, including four horizontal wells seeking attic Devonian reef gas accumulations, were drilled in 2001.

Three gross (three net) successful wells were drilled in the Grouard operating area during 2001, targeting the shallow, gas-prone Cretaceous section and deeper, oil-productive Devonian Gilwood formations. New reserve potential is being delineated in Gilwood structural traps by the application of 3-D seismic data and surface geochemistry.

The Company has set its 2002 Canadian exploitation and development budget at $58 million. During 2002, the Company anticipates drilling 125 gross (100 net) development wells in Canada. Activity will be concentrated in the Sturgeon Lake, Grouard and East of 5 operating areas. Drilling plans include 27 gross (23 net) wells in Sturgeon Lake, 22 gross (20 net) wells in Grouard and 32 gross (24 net) wells in the East of 5 area. Much of the drilling activity will occur in the first quarter of 2002 due to winter-access-only and will capitalize on the exploitation and extension of relatively shallow Cretaceous and Devonian gas pools discovered during the previous winter drilling campaign.

Argentina. 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 continued its highly successful development drilling program in Argentina with the drilling of 68 successful wells in 69 attempts for a 99 percent success rate. With the 1999 acquisition of the El Huemul concession and the 2000 and 2001 acquisitions of the properties in the Cuyo Basin, the Company's development drilling locations in Argentina have increased substantially with 331 drilling locations being recorded in its year-end 2001 proved reserves.

The Company's drilling program in Argentina relies heavily on interpretation of 3-D seismic data to aid in the optimum placement of wells. A total of 56 square miles of new 3-D seismic data was recorded in western Meseta Espinosa Norte and northeast El Huemul in December 2001. Interpretation of this data is underway to identify additional drilling prospects. With this new seismic data, the Company now has 584 square miles of 3-D seismic data which covers 32 percent of the area of all of its operated concessions. The Company believes that significant additional drilling potential will continue to be identified through the acquisition of future 3-D seismic surveys.

Planned 2002 investment activity in the San Jorge Basin includes a reduced level of drilling and workovers as a result of the current political and economic environment in Argentina (see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in this Form 10-K). The total exploitation and development budget for Argentina in 2002 is currently $11 million.

Bolivia. The focus for Bolivia continues to be on maximizing gas sales to existing markets and the development of new gas markets. A geochemical survey is scheduled for the second quarter of 2002. This survey will cover approximately 100 square miles in the Chaco Block, located north of the Chaco Sur exploitation block. The survey will test the probability of encountering gas on structures identified by 2-D seismic data. The Company plans to spend $2 million on exploitation and development activities in Bolivia in 2002 and plans to drill one well in 2003 at an estimated cost of $6.3 million to fulfill its work commitment in this block.

Ecuador. During 2001, activity in Ecuador was focused on the acquisition, processing and interpretation of a 160 square mile 3-D seismic survey covering portions of Blocks 14 and 17 and the Shiripuno Block. A drilling program is scheduled to begin in the second quarter of 2002 to build production capacity to coincide with the expected opening of the OCP pipeline, currently under construction, during the second half of 2003. Four development and extensional drilling locations will be selected and drilled based on the new seismic survey in Blocks 14 and 17. The two wells to be drilled in Block 17 will be horizontal wells and will target measured depths of 12,000 feet and vertical depths of approximately 10,000 feet in the Napo `U' formation. The rig will then move to Block 14 to drill two vertical wells reaching depths of approximately 10,000 feet in the Napo `U' and Basal Tena formations. The Company's 2002 exploitation and development budget includes approximately $16 million for these activities. The Company has a 75 percent working interest in Block 14, a 70 percent working interest in Block 17 and a 100 percent working interest in the Shiripuno Block.

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 North America 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 data, is employed to identify prospects. Exploration in North America is designed to generate reserve growth in this core area 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. The Company's international exploration projects currently underway in Yemen and Trinidad are characterized by higher potential and higher risk.

From January 1, 1999, through December 31, 2001, the Company spent approximately $189.8 million on exploration activities, excluding $53.6 million to acquire the large acreage inventory of Genesis in May 2001. During this period, the Company drilled 92 gross (63 net) exploration wells, of which approximately 62 percent were productive. As a result of all of the Company's exploration activities during the three-year period ended December 31, 2001, the Company succeeded in adding 44.1 MMBOE to proved reserves, replacing approximately 50 percent of production during this period at a cost of $4.31 per BOE. The Company spent approximately $61.8 million on exploration activities during 2001 (excluding $53.6 million to acquire the large acreage inventory of Genesis in May 2001), spending approximately $52.7 million in North America and $9.1 million in its other international areas, adding 21.0 MMBOE to its proved reserves. The Company's 2002 exploration budget has been reduced to $38 million, with approximately $24 million allocated to North American projects and $14 million targeted internationally. This reduction is due to the anticipated lower oil and gas price environment for 2002, as compared to 2001, and the resulting decrease in the Company's cash flow.

In conjunction with its focus on exploitation, the Company has increased its attention on growing reserves through exploration efforts as well. The following is a summary of major exploration activities:

United States. An exploratory well in the Stagecoach prospect, the Cottonwood #1, was successfully completed in late 2001 in the deep Granite Wash of the Dornick Hills formation below 15,800 feet at gross rates exceeding 600 gross (120 net) Bbls of oil per day and five gross (one net) MMcf of gas per day. Additional uphole intervals remain to be completed pending long-term production testing of the current completion interval. A new deep gas play in the pre-Pennsylvanian formation has recently been identified and one well to test that play is planned for 2002.

Another exploratory well in the Little Temple prospect in southern Louisiana was in progress at December 31, 2001, and has now reached total depth of 17,200 feet. Well logs and hydrocarbon shows while drilling indicate approximately 53 feet of net pay in three zones in the middle Miocene formation. Testing to determine the rate and reserve potential of these new zones is expected to be completed by the end of the first quarter of 2002. The Company has a 35 percent working interest in this well.

The Company has identified several new independent projects and leads within the Tiger Bayou 3-D seismic survey in Terrebonne Parish in southern Louisiana. The first prospect generated from this proprietary 3-D seismic survey is the Richaud prospect. This gas prospect will target a deep (20,000 feet), lower Miocene formation that is analogous to the producing horizon in the prolific Lilly Boom field which is adjacent to and on trend with the Richaud prospect. The Company holds a 38 percent working interest in this prospect. Drilling is expected to begin in the second quarter of 2002.

The Company has leased 3,900 net acres in the Val Verde basin of west Texas to develop a lower risk gas play based on horizontal drilling within the Devonian formation. Drilling is expected to begin during the fourth quarter of 2002.

Activity is also underway to develop a balanced portfolio of approximately 10 new exploration prospects during 2002. This work will be concentrated within the three primary areas established for exploration in the United States: southern Louisiana, west Texas and eastern New Mexico, and the Texas gulf coast.

Canada. Consistent with the strategy that led to the entry into Canada, the Company is progressing with a focused endeavor to generate additional impact exploration prospects within the Canadian Western Sedimentary Basin. The majority of these high potential prospects will target gas, which is consistent with Vintage's overall business plan to focus its North American exploration endeavor on significant reserve potential gas prospects.

Due to unseasonably warm weather, normal winter access this season has not been available to the previously drilled exploratory wells within the Northwest Territories license areas. Therefore, completion and testing of these wells has been deferred until freeze-up next winter. During 2002, additional seismic data and surface geochemistry will be acquired to further evaluate the additional exploration potential within these licenses.

Trinidad. In Trinidad, the Company has a 36 percent working interest in two exploration wells, the Carapal Ridge #1 and the Corosan #1, that were drilled in the Central Block during 2001. Both wells successfully encountered gas-bearing sands in the Miocene Herrera formation. The Carapal Ridge well tested five separate intervals at a gross combined daily rate in excess of 50 MMcf of gas and 1,500 Bbls of condensate, while the Corosan well tested two separate intervals at a gross combined daily rate in excess of eight MMcf of gas. In light of these discoveries, evaluation of additional exploration potential that has been identified within the Central Block is underway. The high flow rate potential of the Carapal Ridge discovery resulted in the development of an accelerated plan for an extended production test. The final arrangements necessary to allow this early test to proceed are nearing completion with the expected initiation of the test during the second half of 2002. The Company continues to work closely with Petroleum Company of Trinidad and Tobago Limited (Petrotrin), the state oil company of Trinidad and a 35 percent working interest partner, to identify favorable long-term market options that will allow further development of the project.

Yemen. During 2001, activity in Yemen focused on the acquisition of a new 3-D seismic survey and a complementary, detailed grid geochemical survey in Block S-1. These surveys were completed during the fourth quarter of 2001 and are currently being utilized to evaluate several potentially large exploration opportunities in the sub-salt (Lam) and intra-salt (Alif) sections. These exploration targets are on trend with the adjacent Al-Nasr and Dhahab fields that are currently producing at a combined daily rate of approximately 50 MBbls. The Company has a 75 percent working interest in Block S-1. Current plans for 2002 are to drill up to four prospects. In addition, the Company is continuing to evaluate the commerciality and potential of three wells previously drilled at a total cost of approximately $15.0 million.

Oil and Gas Properties

At December 31, 2001, the Company owned and operated domestic producing properties in nine states, with its U.S. proved reserves located primarily in four core areas: Gulf Coast, East Texas, Mid-Continent and West Coast. In addition, the Company established core areas in Argentina during 1995, Bolivia during 1996, Ecuador in 1998 and Canada in 2000. As of December 31, 2001, the Company operated 4,193 gross (3,703 net) productive wells and also owned non-operating interests in 1,183 gross (685 net) 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 "Divestitures."

The following table sets forth estimates of the proved oil and gas reserves of the Company at December 31, 2001, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina, Ecuador and Trinidad, as estimated by the independent petroleum consultants of DeGolyer and MacNaughton for Bolivia and as estimated by the independent petroleum consultants of Outtrim Szabo Associates Ltd. for Canada:

	Oil (MBbls)			Gas (MMcf)		
	Developed	Undeveloped	Total	Developed	Undeveloped	To
West Coast	41,711	4,606	46,317	89,175	5,080	9
Gulf Coast	17,041	4,281	21,322	63,767	29,642	9
East Texas	7,381	644	8,025	62,600	13,257	7
Mid-Continent	523	761	1,284	36,520	25,108	6

Total U.S.	66,656	10,292	76,948	252,062	73,087	32
Canada	13,259	8,549	21,808	206,539	29,573	23
Total North America ...	79,915	18,841	98,756	458,601	102,660	56
Argentina	101,145	74,682	175,827	48,689	82,705	13
Bolivia	4,670	1,465	6,135	346,148	113,512	45
Ecuador	6,054	44,303	50,357	--	--	
Trinidad	545	641	1,186	25,085	39,324	6
Total Company	192,329	139,932	332,261	878,523	338,201	1,21

Estimates of the Company's 2001 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 concentrated behind-pipe in fields which it operates. Undeveloped proved reserves are predominantly concentrated in development drilling locations and secondary recovery projects.

As discussed in Note 1 to the Company's consolidated financial statements included elsewhere in this Form 10-K, the Argentine government took actions which, in effect, caused the devaluation of the peso in early December 2001. The translation of peso-denominated future production, development and abandonment costs reduced the U.S. dollar cost of these expenses. This cost reduction increased the Company's proved reserves in Argentina by approximately 10.9 MMBOE at December 31, 2001. As discussed in Note 12 to the Company's consolidated financial statements included elsewhere in this Form 10-K, in February 2002, the Argentina government also imposed a 20 percent excise tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. Had this export tax been in effect at December 31, 2001, it would not have materially affected the Company's proved reserve quantities in Argentina.

11

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, 2001, the area comprised 12 percent of the Company's total proved reserves and 47 percent of the Company's U.S. proved reserves. The Company currently operates 1,382 gross (1,346 net) productive wells in this area and owns an interest in 163 gross (13 net) productive wells operated by others. During 2001, net daily production for this area averaged approximately 15,300 BOE, or 39 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, Tejon, Rio Vista and Buena Vista fields. The San Miguelito field also has waterflood potential that may add significant reserves and the Antelope Hills field has significant oil reserves that may be added through steamflood expansion.

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, 2001, the Gulf Coast area comprised approximately seven percent of the Company's total proved reserves and 28 percent of its U.S. proved reserves. The Company currently operates 717 gross (697 net) productive wells in this area and owns an additional interest in 50 gross (13 net) productive wells operated by others. During 2001, net daily production from this area averaged approximately 14,600 BOE, or 38 percent of total net daily U.S. production. A significant inventory of workovers and recompletions exist in Gulf Coast fields from Alabama to south Texas. Development drilling potential is also available in 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 with wells ranging in depth from 1,300 feet to 14,800 feet. The East Texas area comprised approximately four percent of the Company's December 31, 2001, total proved reserves and 16 percent of its U.S. proved reserves. The Company currently operates 522 gross (452 net) productive wells in this area and owns an interest in an additional 43 gross (five net) productive wells operated by others. During 2001, net daily production for this area averaged approximately 5,000 BOE, or 13 percent of total net daily U.S. production. Significant infill drilling potential exists on the Company's acreage in the South Gilmer, Edgewood, Southern Pine 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 two percent of the Company's December 31, 2001, total proved reserves and nine percent of its U.S. proved reserves. The Company currently operates 103 gross (54 net) productive wells in this area and owns an interest in an additional 78 gross (10 net) productive wells operated by others. During 2001, net daily production for this area averaged approximately 3,700 BOE, or 10 percent of total net daily U.S. production. Significant development drilling and recompletion opportunities exist in the Marlow/Velma field. Additional projects to improve the ultimate reserve recovery exist in the Shawnee Townsite waterflood.

Canada. The Company's Canadian producing properties are located in the provinces of Alberta, Saskatchewan and British Columbia. The Company also has approximately 1.2 million net undeveloped acres located in Alberta and Saskatchewan with a significant portion, aggregating to 440,000 net acres, in the Northwest Territories. The Canadian properties comprised approximately 11 percent of the Company's December 31, 2001, proved reserves. The Company currently operates 443 gross (349 net) productive wells in Canada and owns interests in 365 gross (97 net) wells operated by others. During 2001, net daily production averaged approximately 6,000 Bbls of oil and 84,400 Mcf of gas.

Argentina. The Argentina properties consist primarily of 14 mature producing concessions located on the south flank of the San Jorge Basin, all of which are operated by the Company, four concessions located in the Cuyo Basin in western Argentina, two of which are operated by the Company and two non-operated concessions in the Neuguen Basin. These concessions comprised approximately 37 percent of the Company's December 31, 2001, total proved reserves. During 2001, net daily production averaged approximately 28,900 Bbls of oil and 28,090 Mcf of gas. The Company currently operates 1,232 gross (1,232 net) productive wells. In addition, the Company owns an interest in 252 productive wells operated by others. At December 31, 2001, the Company's proved reserves included approximately 331 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 15 percent of the Company's December 31, 2001, total proved reserves and include 15 gross (14 net) productive wells. Net daily production during 2001 averaged approximately 24,900 Mcf of gas and 280 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 one exploration concession. 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 working interest in the Shiripuno exploration concession. The Company currently operates nine gross (seven net) productive wells with 2001 average net daily production of approximately 3,770 Bbls of oil. These concessions comprised nine percent of the Company's December 31, 2001, total proved reserves. Additional infill drilling will be based on interpretation of the 3-D seismic data and will be commensurate with the completion of the OCP pipeline currently estimated to occur during the second half of 2003.

Marketing

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 Canadian oil production is sold under short-term contracts at posted prices. The Company's Argentina oil production is currently sold at port to Esso S.A.P.A. (the Argentina affiliate of Exxon-Mobil), ENAP (the Chilean government-owned oil company) 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. During 2001, approximately 10 percent and 12 percent of the Company's total operating revenues related to oil sales to ENAP and Esso S.A.P.A., respectively.

In January 2002, the Argentine government devalued the Argentine peso ("peso") and enacted an emergency law that required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Subsequently, on February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. For additional information, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in this From 10-K. Domestic Argentine oil sales are now being paid in pesos, while export oil sales continue to be paid in U.S. dollars.

The Company currently exports approximately 35 percent of its Argentina oil production. However, the Company believes that this export tax will have the effect of decreasing all future Argentina oil revenues (not only export revenues) by the tax rate for the duration of the tax. The Company believes that the U.S. dollar equivalent value for domestic Argentina oil sales (now paid in pesos) will move over time to parity with the U.S. dollar-denominated export values, net of the export tax, thus impacting domestic Argentina values by a like percentage to the tax. The adverse impact of this tax will be partially offset by the net cost savings from the devaluation of the peso on peso-denominated costs and may be further reduced by the Argentina income tax savings related to deducting such impact.

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 North American gas is committed to long-term fixed-price contracts, the Company is positioned to take advantage of future strong gas price environments, 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. The Company's Argentina average gas price was historically determined primarily by the realized oil price from the El Huemul concession under a gas for oil exchange arrangement which expired at the end of 2001. Beginning in 2002, the Company's Argentina gas will be sold under spot contracts of varying lengths and, as a result of the emergency law enacted in January 2002, must now be paid in pesos as a result of the emergency law enacted in January 2002. This will initially result in a decrease in sales revenue value when converted to U.S. dollars due to the devaluation of the peso and current market conditions. This value may improve over time as domestic Argentina gas drilling declines and market conditions improve.

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 two affiliates of Enron South America (the "Enron affiliates"). The terms of the short-term contract allowed one of the Enron affiliates to 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. The terms of the long-term agreement allowed the other of the Enron affiliates to purchase up to 15.4 MMcf of gas per day contingent upon its development of emerging market opportunities in Brazil and Argentina. Sales under the short-term contract began in April 2001 and the Company has received payments in a timely manner. The Company has been notified that the short-term contract will not be renewed at its expiration on March 31, 2002, and that the long-term contract will be canceled prior to the commencement of gas deliveries. The terms of the long-term contract require the Enron affiliate to make a $1.5 million payment to the Company in order to effect the early termination. No such payment has been received. The Company is pursuing other alternative markets for its Bolivia gas and believes that it is well positioned to continue to develop markets as gas consumption continues to grow in the Southern Cone.

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) covering approximately 2.2 MMBbls at a weighted average price of $23.77 per Bbl (NYMEX reference price) for various periods in the first half of 2002. The Company has also entered into various gas hedges (swap agreements) covering approximately 8.6 million MMBtu of its gas production over the period from April through October 2002. The Canadian portion of the gas swap agreements (approximately 4.3 million MMBtu) is at the AECO gas price index reference price of 3.58 Canadian dollars per MMBtu and will be settled in Canadian dollars. The AECO gas price index is the reference price used for most of the Company's Canadian gas spot sales. The U.S. portion of the gas swap agreements (approximately 4.3 million MMBtu) is at a NYMEX reference price of $2.60 per MMBtu. Additionally, the Company has entered into basis swap agreements for the approximately 4.3 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. The Company continues to monitor oil and gas prices and may enter into additional oil and gas hedges or swaps in the future.

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

Quarter Ending	Bbls	NYMEX Reference Price Per Bbl
	(in thousands)	
March 31, 2002	1,150	$ 23.73
June 30, 2002	1,055	23.82

The following table reflects the MMBtu hedged in the U.S. and the corresponding NYMEX reference price by quarter:

Quarter Ending	MMBtu	NYMEX Reference Price Per MMBtu
June 30, 2002	1,820,000	$ 2.60
September 30, 2002	2,440,000	2.60
December 31, 2002	620,000	2.60

The following table reflects the MMBtu hedged in Canada and the corresponding AECO reference price by quarter:

Quarter Ending	MMBtu	AECO Reference Price Per MMBtu
		(Canadian dollars)
June 30, 2002	1,819,903	C$ 3.58
September 30, 2002	2,439,870	3.58
December 31, 2002	619,967	3.58

The counterparties to the Company's swap agreements are commercial banks. The Company had no derivative contracts with Enron Corp. or its affiliates but does have minimal credit exposure of approximately $300,000 to Enron North America Corp., which filed a voluntary petition for Chapter 11 reorganization in U.S. bankruptcy court along with Enron Corp., in addition to the previously described contracts for Bolivia gas.

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 11 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 223 miles of varying diameter pipe with a combined capacity in excess of 186 MMcf of gas per day. At December 31, 2001, there were 74 wells (61 of 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.

In 1999, the Company obtained ownership and operatorship of the Santa Clara Valley gas plant located in Ventura County, California. This 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, natural gas liquids 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 is obtained from the process with a turbo-expander compressor.

The plant is currently processing approximately eight MMcf of gas per day and producing approximately 24,000 gallons per day of natural gas liquids (butane/propane). The natural gas liquids 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.

Reserves

At December 31, 2001, the Company had proved reserves of 535.0 MMBOE, comprised of 332.3 MMBbls of oil and 1.2 Tcf of gas, as estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina, Ecuador and Trinidad, as estimated by the independent petroleum consultants of DeGolyer and MacNaughton for Bolivia and as estimated by the independent petroleum consultants of Outtrim Szabo Associates Ltd. 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, 2001, the present value of future net revenues (revenues less production, development and abandonment costs) before income taxes attributable to the Company's proved reserves at such date (in thousands):

Proved Reserves:	
Future net revenues	$3,418,869
Present value of future net revenues before income taxes, discounted at 10 percent	1,914,073
Standardized measure of discounted future net cash flows ...	1,438,141
Proved Developed Reserves:	

Future net revenues..	$2,207,477
Present value of future net revenues before income taxes, discounted at 10 percent	1,425,059

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, 2001, economic conditions. The estimated future production is priced at prices prevailing at December 31, 2001. The resulting estimated future gross revenues are reduced by estimated future costs to develop and produce the proved reserves and by estimated future abandonment costs, based on December 31, 2001, cost levels, but such costs do not include debt service, general and administrative expenses and income taxes.

As discussed in Note 1 to the Company's consolidated financial statements included elsewhere in this Form 10-K, the Argentine government took actions which in effect caused the devaluation of the peso in early December 2001. The translation of peso-denominated future production, development and abandonment costs reduced the U.S. dollar cost of these expenses. This cost reduction increased the Company's proved reserves in Argentina by approximately 10.9 MMBOE, increased the Company's present value of future net revenues before income taxes, discounted at 10 percent for proved reserves by approximately $101.9 million and increased the Company's standardized measure of discounted future net cash flows by approximately $68.2 million at December 31, 2001.

As discussed in Note 12 to the Company's consolidated financial statements included elsewhere in this Form 10-K, in February 2002, the Argentine government also imposed a 20 percent excise tax on oil exports, effective March 1, 2002. This tax is limited by law to a term of no more than five years. Had this export tax been in effect at December 31, 2001, it would not have materially affected the Company's proved reserve quantities in Argentina, but it would have reduced the Company's present value of future net revenues before income taxes, discounted at 10 percent for proved reserves by approximately $145.2 million and reduced the Company's standardized measure of discounted future net cash flows by approximately $98.8 million.

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 11 "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 11 "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, 2001:

	Developed Acreage		Productive Wells: Oil		Productive Wells: Gas	
	Gross	Net	Gross	Net	Gross	Net
U.S.	484,018	355,380	2,472	2,225	586	366
Canada	431,897	209,969	239	153	569	293
Argentina	217,848	181,894	1,473	1,318	11	11
Bolivia	76,603	65,483	-	-	15	14
Ecuador	33,425	24,745	9	7	-	-
Trinidad	160	58	-	-	2	1
Total	1,243,951	837,529	4,193	3,703	1,183	685

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.

17

Undeveloped Acreage

At December 31, 2001, the Company held the following undeveloped acres located in the U.S., Canada, Argentina, Bolivia, Ecuador, Yemen, Trinidad and other international areas. With respect to such U.S. acreage held under leases, 104,219 gross (55,143 net) acres are held under leases with primary terms that expire at varying dates through December 31, 2005, unless commercial production has commenced. With respect to such Canadian acreage held under leases, 1,819,642 gross (1,057,798 net) acres are held under leases with primary terms that expire at varying dates through December 31, 2005, unless commercial production has commenced. The Company has the option to relinquish portions of its undeveloped acreage in Argentina at various dates through 2007 or pay increased mining royalties. The Bolivia acreage is held under concessions with terms that expire at varying dates in 2003. The Yemen acreage is held under concessions with terms that expire in 2002; however, the Company will begin Phase II of its exploration program in Yemen in March 2002, which will extend the acreage expiration to 2004. The Ecuador concessions have primary terms that expire at various dates in 2005, 2006 and 2007 unless there is a commercial discovery.

State/Country	Gross Acres	Net Acres
California	7,204	6,595
Colorado	1,248	468
Louisiana	7,622	2,820
North Dakota	31,131	18,617
Oklahoma	43,578	20,623
Texas	18,620	9,586
Wyoming	9,500	3,505
Total U.S.	118,903	62,214
Canada	2,182,747	1,232,399
Argentina	1,407,802	1,206,105
Bolivia	336,989	336,989
Ecuador	782,134	579,520
Yemen	1,108,019	831,014
Trinidad	27,278	9,820
Other International Areas	275,107	192,575
Total Company	6,238,979	4,450,636

18

Production; Unit Prices; Costs

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

	Years Ended December 31,		
	2001	2000	1999
Production:			
Oil (MBbls) -			
U.S.	8,409	9,044	8,643
Canada	1,539	19	-
Argentina	10,548	9,406	7,560
Ecuador	1,375	1,261	597
Bolivia	101	131	77
Trinidad	2	-	-
Total	21,974(a)	19,861(b)	16,877
Gas (MMcf) -			
U.S.	34,168	35,764	39,150
Canada	22,132	312	-
Argentina	10,253	8,705	4,682
Bolivia	9,088	8,948	4,522
Total	75,641	53,729	48,354
Total MBOE	34,581	28,816	24,936
Average Sales Prices:			
Oil (per Bbl) -			
U.S.	$ 23.08(c)	$ 22.85(d)	$ 15.92(e)
Canada	20.55	26.05	-

Argentina (f).............	21.80(c)	28.25	18.00
Ecuador (f)...............	17.65	24.27	17.28
Bolivia (f)...............	20.06	29.62	19.05
Total (f)..............	21.93(c)	25.55(d)	16.92(e)
Gas (per Mcf) -			
U.S.......................	$ 4.83	$ 3.91	$ 2.06
Canada....................	2.50	5.73	-
Argentina.................	1.30	1.79	1.34
Bolivia (f)...............	1.72	1.75	.96
Total (f)..............	3.30	3.22	1.89
Production Costs (per BOE):			
U.S............................	$ 7.56	$ 6.42	$ 5.31
Canada.........................	6.23	7.09	-
Argentina (f)..................	4.98	4.87	4.30
Bolivia (f)....................	2.71	2.33	3.64
Ecuador (f)....................	6.47	4.85	3.82
Total (f).................	6.18	5.54	4.88

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) Total production for 2001, before the impact of changes in inventories, was 22,094 MBbls (Argentina- 10,644 MBbls, Bolivia- 125 MBbls).

(b) Total production for 2000, before the impact of changes in inventories, was 19,921 MBbls (Argentina- 9,512 MBbls, Ecuador- 1,227 MBbls, Bolivia- 119 MBbls).

(c) Reflects the impact of oil hedges which increased the Company's 2001 U.S., Argentina and total average oil prices per Bbl by 91 cents, $1.14 and 89 cents, respectively.

(d) 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.

(e) 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.

(f) The 1999 amounts have been restated to reflect the reclassification of transportation and storage costs to lease operating costs.

19

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,					
	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Development:						

United States -						
Productive................	16	7.40	21	14.93	6	1.94
Non-Productive............	2	1.45	2	1.68	-	-
Canada						
Productive................	47	33.40	-	-	-	-
Non-Productive............	7	6.80	-	-	-	-
Argentina -						
Productive................	68	68.00	40	40.00	10	10.00
Non-Productive............	1	1.00	1	1.00	1	1.00
Bolivia -						
Productive................	-	-	-	-	1	1.00
Non-Productive............	-	-	-	-	-	-
Ecuador						
Productive................	1	0.75	-	-	-	-
Non-Productive............	-	-	-	-	-	-
Total	142	118.80	64	57.61	18	13.94
Exploratory:						
United States -						
Productive................	7	4.44	14	6.17	1	0.47
Non-Productive............	4	2.53	4	2.02	11	5.56
Canada -						
Productive................	26	20.00	-	-	-	-
Non-Productive............	10	8.90	1	0.45	-	-
Bolivia						
Productive................	-	-	-	-	7	7.00
Non-Productive............	-	-	3	3.00	-	-
Ecuador -						
Productive................	-	-	-	-	-	-
Non-Productive............	-	-	1	1.00	-	-
Yemen -						
Productive................	-	-	-	-	-	-
Non-Productive............	-	-	1	0.75	-	-
Trinidad						
Productive................	2	0.72	-	-	-	-
Non-Productive............	-	-	-	-	-	-
Total	49	36.59	24	13.39	19	13.03
Total:						
Productive................	167	134.71	75	61.10	25	20.41
Non-Productive............	24	20.68	13	9.90	12	6.56
Total................	191	155.39	88	71.00	37	26.97

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

At December 31, 2001, the Company was a participant in the drilling, completion or evaluation of 12 gross (10 net) wells. All of the Company's drilling activities are conducted with independent contractors. The Company owns no drilling equipment.

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 for 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 non-compliance. 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 land and leases to facilitate exploration, while other states rely on voluntary pooling of land 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 U.S. 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 holding 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 U.S. 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 (the "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 was required 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 to make short-term capacity release more viable and to foster a more competitive and transparent market in which prices are more efficient. Among other things, Order 637 removes the price cap on short-term capacity releases, allows peak/off peak 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 the FERC's decision to allow 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 are subject to the laws and regulations established there. Beginning in December 2001, new measures have been enacted by law and executive order that may materially impact, among other items, (i) the realized prices the Company receives for oil and gas it produces and sells as a result of export taxes; (ii) the timing of repatriations of cash to the U.S.; (iii) the Company's asset valuations; and (iv) peso-denominated monetary assets and liabilities. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk."

The Company's operations in Canada, Bolivia, Ecuador, Yemen and Trinidad are subject to various laws and regulations in those countries. Those 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. The Company's Trinidad project is dependent, in part, on the ability to identify favorable long-term market options for its gas production.

Risk Factors

The following risks and uncertainties should be carefully considered when reading this Form 10-K. If any of the events described below were to occur, they could have a material adverse effect on the Company's business, financial condition and operating results.

Oil and gas prices fluctuate widely, and low oil and gas prices could adversely affect, and in the past have adversely affected, the Company's financial results.

The Company's revenues, operating results, cash flow and future rate of growth depend substantially upon prevailing prices for oil and gas. Historically, oil and gas prices and markets have been volatile and are likely to continue to be volatile in the future. The average prices that the Company currently receives for its production are comparable to their historical averages. However, a future significant decrease in oil and gas prices, such as that experienced in 1998 and the first half of 1999, could have a material adverse effect on the Company's cash flow and profitability. The substantial and extended decline in oil and gas prices during 1998 and 1999 adversely affected the Company's financial condition and results of operations. A sustained period of low prices could have a material adverse effect on the Company's earnings and financial condition.

Prices for oil and gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors that are beyond the Company's control, including:

- political conditions in oil producing regions, including the Middle East;
- domestic and foreign supplies of oil and gas;
- levels of consumer demand;
- weather conditions;
- domestic and foreign government regulations;
- prices and availability of alternative fuels; and

- overall economic conditions.

In addition, various factors may adversely affect the Company's ability to market its oil and gas production, including:

- capacity and availability of oil and gas gathering systems and pipelines;
- effects of federal and state regulation of production and transportation;
- general economic conditions;
- changes in supply due to drilling by other producers;
- availability of drilling rigs; and
- changes in demand.

Lower oil and gas prices may adversely affect the Company's level of capital expenditures, reserve estimates and borrowing capacity.

Lower oil and gas prices, such as those experienced by the Company in 1998 and the first half of 1999, have various adverse effects on the Company's business, including reducing cash flows which, among other things, have caused the Company in the past, and may cause the Company in the future, to decrease its capital expenditures. A smaller capital expenditure program may adversely affect the Company's ability to increase or maintain its reserve and production levels. Lower prices may also result in reduced reserve estimates, one-time write-offs of impaired assets and decreased earnings or losses due to lower reserves and higher depreciation, depletion and amortization expense. For example, in the fourth quarter of 1998 the Company recorded a significant non-cash charge for the impairment of the Company's oil and gas properties due to lower oil and gas prices.

The amount the Company can borrow under its revolving credit facility is subject to periodic redetermination based, in part, on expectations of future oil and gas prices applied to the Company's oil and gas reserve estimates. Lower oil and gas prices could result in future reductions in the borrowing base under the Company's revolving credit facility because lower oil and gas reserve values would reduce the Company's liquidity and possibly trigger mandatory loan repayments. Furthermore, reduction in the Company's liquidity could impede its ability to fund future acquisitions. Lower prices may also cause the Company to not be in compliance with maintenance covenants under its revolving credit facility and may negatively affect its credit statistics and coverage ratios.

The Company's significant level of indebtedness requires that a significant portion of its cash flow be used to pay interest and may limit its ability to fund capital expenditures or obtain additional financing to fund other obligations.

The Company currently has a significant amount of indebtedness. At December 31, 2001, the Company's total long-term debt outstanding was approximately $1.0 billion and the Company had a long-term debt to total capitalization ratio of 57.7 percent. The Company's significant indebtedness could have important consequences. For example:

- the Company's ability to obtain any necessary financing in the future for working capital, capital expenditures, acquisitions, debt service requirements or other purposes may be limited;

- a portion of the Company's cash flow from operations must be utilized for the payment of interest on its indebtedness and will not be available for financing capital expenditures or other purposes; for example, interest payments for 2001 represented approximately 16 percent of the Company's cash flows from operations before working capital changes and interest expense;

o the Company's level of indebtedness and the covenants governing its current indebtedness could limit the Company's flexibility in planning for, or reacting to, changes in its business because certain financing options may be limited or prohibited;

o the Company is more highly leveraged than some of its competitors, which may place the Company at a competitive disadvantage;

o the Company's level of indebtedness may make it more vulnerable during periods of low oil and gas prices or in the event of a downturn in its business because of its fixed debt service obligations; and

o the terms of the Company's revolving credit facility require interest and principal payments and maintenance of stated financial covenants. If the requirements of this facility are not satisfied, the lenders under this facility would be entitled to accelerate the payment of all outstanding indebtedness under this facility, and a default would be deemed to have occurred under the terms of the Company's outstanding senior subordinated notes. In such event, the Company cannot provide assurance that it would have sufficient funds available or could obtain the financing required to meet its obligations.

The Company may be able to incur substantial additional indebtedness in the future. The Company's revolving credit facility would permit additional borrowings of up to approximately $200 million, as of December 31, 2001. For further discussion of the Company's borrowing base, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity." If the Company were to add additional indebtedness to its current debt levels, the related risks discussed above, which it now faces, could intensify.

The Company's future performance depends upon its ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless the Company successfully replaces the reserves that it produces, its reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operations. The Company has historically succeeded in substantially replacing reserves through acquisition, exploitation, development and exploration. The Company has conducted such activities on its existing oil and gas properties as well as on newly acquired properties. The Company may not be able to continue to replace reserves from such activities at acceptable costs. Lower oil and gas prices may further limit the kinds of reserves that can be developed at acceptable costs. Lower prices also decrease the Company's cash flow and may cause it to reduce capital expenditures. The business of exploring for, developing or acquiring reserves is capital intensive. The Company may not be able to make the necessary capital investments to maintain or expand its oil and gas reserves if cash flow from operations is reduced and external sources of capital become limited or unavailable. In addition, exploitation, development and exploration involve numerous risks that may result in dry holes, the failure to produce oil and gas in commercial quantities and the inability to fully produce discovered reserves.

The Company is continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than those it has consummated to date. The Company cannot ensure that it will successfully consummate any acquisition, that it will be able to acquire producing oil and gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into its operations.

Acquisitions carry unknown risks including the potential for environmental problems.

The Company's focus on acquiring producing oil and gas properties may increase its potential exposure to liabilities and costs for environmental and other problems existing on such properties. The Company expects to continue to focus, as it has done in the past, on acquiring producing oil and gas properties to replace reserves. Although the Company performs reviews of the acquired properties that it believes are consistent with industry practice, such reviews are inherently incomplete. In general, it is not feasible to review in depth each individual property being acquired. Ordinarily, the Company focuses its review efforts on the higher-valued properties and samples the remainder. However, even an in-depth review of all properties and records may not necessarily reveal existing or potential problems, nor will it permit the Company to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on each well included in an acquisition, and environmental problems, such as ground water contamination and surface and subsurface damages from leakage, spills, disposal or other releases of hazardous substances on such properties or from adjoining properties that have migrated to such properties, are not necessarily observable even when an inspection is performed.

Estimating reserves and future net revenues involves uncertainties and oil and gas price declines may lead to impairment of oil and gas assets.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this Form 10-K represent only estimates. In addition, the estimates of future net revenues from the Company's proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct over time.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Lower oil and gas prices may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, thus reducing proved property reserve estimates. If such revisions in the estimated quantities of proved reserves were to occur, they would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. The revisions may also be sufficient to trigger impairment losses on certain properties which would result in a further non-cash charge to earnings. For example, the Company recorded a significant non-cash charge for the impairment of oil and gas properties in the fourth quarter of 1998 due to lower oil and gas prices.

The Company's international operations may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors.

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 Canada, Argentina, Bolivia, Ecuador, Yemen and Trinidad. For 2001, the Company's operations in Argentina accounted for approximately 27 percent of the Company's revenues, 39 percent of the Company's net operating profit (pre-tax income before impairments of oil and gas properties, goodwill amortization and general and administrative and interest expense) and 25 percent of its total assets. During 2001, the Company's operations in Argentina represented its only foreign operations accounting for more than 10 percent of its revenues or net operating profit (pre-tax income before impairments of oil and gas properties and general and administrative and interest expense). The Company's operations in Canada accounted for approximately 39 percent of its total assets, including goodwill, at December 31, 2001. A majority of these Canadian assets were purchased on May 2, 2001, as part of the acquisition of Genesis. The Company's exploration and production operations include only eight months of the operations of Genesis in 2001. At December 31, 2001, none of the Company's other international operations accounted for more than 10 percent of its 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.

The Company's foreign properties, operations or investments in Canada, Argentina, Bolivia, Ecuador, Yemen and Trinidad may be adversely affected by a number of factors. For example:

- local political and economic developments could restrict or increase the cost of the Company's foreign operations;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive tax claims could increase costs of the Company's foreign operations;
- expropriation of the Company's property could result in loss of revenue, property and equipment;
- import and export regulations and other foreign laws or policies could result in loss of revenues; and
- laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict the Company's ability to fund foreign operations or may make foreign operations more costly.

In particular, the Company's Bolivian projects are dependent, at least in part, on the operation of the Bolivia-to-Brazil gas pipeline. The operation of this pipeline is subject to various factors outside the Company's control. In addition, in the event of a dispute arising from foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts in the U.S. The Company may also be hindered or prevented from enforcing its rights with respect to actions taken by a foreign government or its agencies.

The Argentina economic and political situation continues to evolve and the Argentine government may enact future regulations or policies that, when finalized and adopted, may materially impact, among other items:

- the realized prices the Company receives for oil and gas that it produces and sells as a result of export taxes;
- the timing of repatriations of cash to the U.S.;

- the Company's asset valuations; and
- peso-denominated monetary assets and liabilities.

See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in this Form 10-K.

The Company's hedging activities may expose the Company to the risk of financial loss in certain circumstances.

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 impact of changes in market prices for oil and gas on the average oil and gas prices received by the Company may be reduced based on the level of the Company's hedging activities. These hedging arrangements may limit the Company's potential gains if the market prices for oil and gas were to rise substantially over the price established by the hedge. In addition, the Company's hedging arrangements expose it to the risk of financial loss in certain circumstances, including instances in which:

- production is less than expected;
- a change in the difference between published price indexes established by pipelines in which the Company's hedged production is delivered and the reference price established in the hedging arrangements is such that the Company is required to make payments to the counterparties to the Company's arrangements; or
- the counterparties to the Company's hedging arrangements fail to honor their financial commitments.

The Company currently has contracts hedging 2.2 MBbls of oil for various periods in the first half of 2002 at an average NYMEX reference price of $23.77 per Bbl, contracts hedging 4.3 million MMBtu of U.S. gas for 2002 at a NYMEX reference price of $2.60 per MMBtu and a contract hedging 4.3 million MMBtu of Canadian gas for 2002 at an AECO reference price of 3.58 Canadian dollars per MMBtu.

Uninsured risks associated with the Company's operations could result in a substantial financial loss.

The Company's operations are subject to all of the risks and hazards typically associated with the exploitation, development and exploration for, and the production and transportation of oil and gas. These operating risks include, but are not limited to:

- blowouts, cratering and explosions;
- uncontrollable flows of oil, natural gas or well fluids;
- fires;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

Any of these events could result in loss of human life, significant damage to property, environmental pollution, impairment of the Company's operations and substantial losses to the Company. In accordance with customary industry practice, the Company maintains insurance against some, but not all, of such risks and losses. The occurrence of such an event not fully covered by insurance could have a material adverse effect on the Company's financial position and results of operations.

Governmental and environmental regulations could adversely affect the Company's business.

The Company's business is subject to certain foreign, federal, state and local laws and regulations on taxation, the exploration for and development, production and marketing of oil and gas, and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, prevention of waste and other matters. Such laws and regulations have increased the costs of planning, designing, drilling, installing, operating and abandoning the Company's oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where the Company has production, could limit the total number of wells drilled or the allowable production from successful wells, which could decrease the Company's revenues.

The Company's operations are subject to complex environmental laws and regulations adopted by the various jurisdictions where the Company operates. The Company could incur liabilities to governments or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water, including responsibility for remedial costs. The Company could potentially discharge such materials into the environment in any of the following ways:

- from a well or drilling equipment at a drill site;
- leakage from gathering systems, pipelines, transportation facilities and storage tanks;
- damage to oil and natural gas wells resulting from accidents during normal operations; and
- blowouts, cratering and explosions.

Because the requirements imposed by such laws and regulations are frequently changed, the Company cannot ensure that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect the Company's business. In addition, because the Company acquires interests in properties that have been previously operated by others, the Company may be liable for environmental damage caused by such former operators.

Industry competition may impede the Company's growth.

The oil and gas industry is highly competitive, and the Company may not be able to compete successfully or grow its business. The Company competes in the areas of property acquisitions and the development, production and marketing of, and exploration for, oil and gas with major oil companies, other independent oil and gas concerns and individual producers and operators. The Company also competes with major and independent oil and gas concerns in recruiting and retaining qualified employees. Many of these competitors have substantially greater financial and other resources than the Company. The Company may not be able to successfully expand its business or attract or retain qualified employees.

Employees

The Company employs approximately 240 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 180 full-time employees are responsible for the supervision and operation of its U.S. field activities. The Company also employs approximately 350 people for the management and operation of its properties in Canada, Argentina, Bolivia, Ecuador 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, 2001.

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........	65	Director and Chairman of the Board of Directors
S. Craig George..................	49	Director, President and Chief Executive Officer
William L. Abernathy.............	50	Director, Executive Vice President and Chief Operating
William C. Barnes................	47	Director, Executive Vice President, Chief Financial Of Secretary and Treasurer
William E. Dozier................	49	Senior Vice President - Operations
Kellam Colquitt..................	54	Vice President - Exploration
Robert W. Cox....................	56	Vice President - General Counsel
Andy R. Lowe.....................	50	Vice President - Marketing
Michael F. Meimerstorf...........	45	Vice President and Controller
Robert E. Phaneuf................	55	Vice President - Corporate Development
Larry W. Sheppard................	47	Vice President - New Ventures
Martin L. Thalken................	41	Vice President - Acquisitions
Gary A. Watson...................	44	Vice President - Canadian Operations

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 42 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.

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. Colquitt has been Vice President--Exploration of the Company since May 2001. From April 2000 to May 2001, he was General Manager--North American Exploration of the Company. He was employed by Ranger Oil Company, an independent oil and gas company, from August 1995 to January 2000 where he served as Vice President, International Exploration--Western Hemisphere and Vice President, U.S. Operations. From December 1983 to July 1995 he was employed by Santa Fe Minerals serving as Manager--International Exploitation, Exploration and Production, and in various other management and supervisory capacities. He was President of Colquitt Exploration, Inc. from 1978 to December 1983, providing contract exploration services. From 1971 to 1978, he served in various geology and supervisory capacities for Placid Oil Company. He has a B.S. Degree in Geology from Texas A&M University.

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--New Ventures of the Company since May 2001. From November 1994 to May 2001, he was Vice President--International of the Company. 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.

Mr. Watson has been Vice President--Canadian Operations of the Company since June 2001. He was General Manager--Latin American Operations of the Company from February 1998 to June 2001 and General Manager--Vintage Oil Argentina, Inc. from August 1995 to February 1998. From March 1987 to July 1995, he was employed by Santa Fe Minerals where he held various engineering and management positions serving most recently as Manager of Project Development. From August 1985 to January 1987, he was employed by Williams Exploration Company as an engineer, with assignments in operations and reservoir engineering. From September 1984 to July 1985, he was Bank Representative in the Energy Group of Texas Commerce Bank. From May 1979 to August 1984, he was employed by Texaco, Inc. as an engineer in the New Orleans Division. He has a B.S. Degree in Chemical Engineering (Petroleum Option) from the University of Pittsburgh.

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 sales 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
2001			
First Quarter...............	$ 22.81	$ 18.44	$ .03
Second Quarter..............	22.20	18.02	.03
Third Quarter...............	20.25	14.75	.035
Fourth Quarter..............	18.95	11.77	.035
2000			
First Quarter...............	$ 20.56	$ 11.19	$ .025
Second Quarter..............	25.13	18.13	.025
Third Quarter...............	24.75	16.81	.03
Fourth Quarter..............	27.94	18.13	.03

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, 2001, the common stock was held by 168 holders of record and approximately 16,500 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 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 Company is prohibited from paying cash dividends if the Company's Consolidated Interest Coverage Ratio (as defined in indentures) does not exceed 2.5 to 1.0. The Company is also prohibited from paying 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 equity offerings subsequent to November 30, 2000, 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 $559 million at December 31, 2001.

Item 6. Selected Financial Data.

SELECTED FINANCIAL AND OPERATING DATA

	Years Ended December 31,			
	2001	2000	1999	199
	(In thousands, except per share amounts and			
Income Statement Data:				
Oil and gas sales (a)............................	$ 731,386	$ 680,350	$ 376,924	$ 27
Gas marketing revenues..........................	130,209	128,836	60,275	5
Gathering revenues..............................	17,032	19,998	6,955	
Total revenues (a)..............................	909,241	806,181	502,928	33
Operating expenses (a)..........................	357,683	300,477	184,367	18
Exploration costs...............................	22,073	25,242	14,674	2
Depreciation, depletion and amortization.........	168,944	100,109	107,807	10
Impairment of oil and gas properties............	29,050	225	3,306	7
Amortization of goodwill........................	11,940	-	-	
Interest..	64,728	48,437	58,665	4
Net income (loss)...............................	133,507	195,893	73,371	(8
Income (loss) per share before cumulative effect of change in accounting principle:				
Basic..................................	2.12	3.15	1.27	
Diluted................................	2.09	3.08	1.24	
Income (loss) per share:				
Basic..................................	2.12	3.13	1.27	
Diluted................................	2.09	3.06	1.24	
Dividends declared per share....................	.14	.14	-	

Balance Sheet Data (end of year):				
Total assets	$ 2,096,788	$ 1,338,397	$ 1,168,134	$ 1,01
Long-term debt	1,010,673	464,229	625,318	67
Stockholders' equity	729,443	624,857	431,129	27
Operating Data:				
Production:				
Oil (MBbls)	21,974	19,861	16,877	1
Gas (MMcf)	75,641	53,729	48,354	4
Average Sales Prices:				
Oil (per Bbl)	$ 21.93	$ 25.55	$ 16.92	$
Gas (per Mcf)	3.30	3.22	1.89	
Proved Reserves (end of year):				
Oil (MBbls)	332,261	318,560	303,190	16
Gas (MMcf)	1,216,724	1,023,208	988,989	80
Total proved reserves (MBOE)	535,048	489,095	468,022	29
Present value of estimated future net revenues before income taxes discounted at 10 percent (in thousands):				
Oil and gas properties	$ 1,914,073	$ 4,338,616	$ 2,989,626	$ 70
Gathering systems and plant	1,182	14,188	13,764	
Standardized measure of discounted future net cash flows (in thousands)	1,438,141	2,951,121	2,247,237	64

(a) The 1999, 1998 and 1997 amounts have been restated to reflect the reclassification of transportation and storage costs to lease operating costs.

Significant acquisitions of producing oil and gas properties during 2001, 1999 and 1997 and significant dispositions of oil and gas properties during 2001 and 1999 affect the comparability between the Financial and Operating Data for the years presented above.

34

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,		
	2001	2000	1999
Production:			
Oil (MBbls) -			

U.S.	8,409	9,044	8,643
Canada	1,539	19	-
Argentina	10,548	9,406	7,560
Ecuador	1,375	1,261	597
Bolivia	101	131	77
Trinidad	2	-	-
Total	21,974(a)	19,861(b)	16,877
Gas (MMcf) -			
U.S.	34,168	35,764	39,150
Canada	22,132	312	-
Argentina	10,253	8,705	4,682
Bolivia	9,088	8,948	4,522
Total	75,641	53,729	48,354
Total MBOE	34,581	28,816	24,936
Average Sales Prices:			
Oil (per Bbl) -			
U.S.	$ 23.08(c)	$ 22.85(d)	$ 15.92(e)
Canada	20.55	26.05	-
Argentina	21.80(c)	28.25	18.00
Ecuador	17.65	24.27	17.28
Bolivia	20.06	29.62	19.05
Total	21.93(c)	25.55(d)	16.92(e)
Gas (per Mcf) -			
U.S.	$ 4.83	$ 3.91	$ 2.06
Canada	2.50	5.73	-
Argentina	1.30	1.79	1.34
Bolivia	1.72	1.75	.96
Total	3.30	3.22	1.89

(a) Total production for 2001, before the impact of changes in inventories, was 22,094 MBbls (Argentina- 10,644 MBbls, Bolivia- 125 MBbls).

(b) Total production for 2000, before the impact of changes in inventories, was 19,921 MBbls (Argentina- 9,512 MBbls, Ecuador- 1,227 MBbls, Bolivia- 119 MBbls).

(c) Reflects the impact of oil hedges which increased the Company's 2001 U.S., Argentina and total average oil prices per Bbl by 91 cents, $1.14 and 89 cents, respectively.

(d) 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.

(e) 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.

35

Average U.S. and Canada 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. The Company's Ecuador oil production is sold to various third party purchasers at West Texas Intermediate spot prices less a specified differential. In 2001, the Company experienced a 14 percent decrease in its average oil price, including the impact of hedging activities (23 percent decrease excluding hedging activities), compared to 2000. The Company experienced a 51 percent increase in its average oil price, including the impact of hedging activities (63 percent increase excluding hedging activities) in 2000 compared to 1999 as a result of OPEC's efforts to reduce the available supply of crude oil in the global markets along with increasing demand.

As discussed in Note 1 to the Company's consolidated financial statements included elsewhere in this Form 10-K, the Argentine government took actions which in effect caused the devaluation of the peso in early December 2001 and, in January 2002, enacted an emergency law that required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Subsequently, on February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. For additional information, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in this Form 10-K. Domestic Argentina oil sales are now being paid in pesos, while export oil sales continue to be paid in U.S. dollars.

The Company currently exports approximately 35 percent of its Argentina oil production. However, the Company believes that this export tax will have the effect of decreasing all future Argentina oil revenues (not only export revenues) by the tax rate for the duration of the tax. The Company believes the U.S. dollar equivalent value for domestic Argentina oil sales (now paid in pesos) will move over time to parity with the U.S. dollar-denominated export values, net of the export tax, thus impacting domestic Argentina values by a like percentage to the tax. The adverse impact of this tax will be partially offset by the net cost savings from the devaluation of the peso on peso-denominated costs and may be further reduced by the Argentina income tax savings related to deducting such impact.

The Company participated in oil hedges covering 5.5 MMBbls, 9.3 MMBbls and 1.8 MMBbls in 2001, 2000 and 1999, respectively. The impact of the 2001 hedges increased the Company's U.S. average oil price by 91 cents to $23.08 per Bbl, its Argentina average oil price by $1.14 to $21.80 per Bbl and its overall average oil price by 89 cents to $21.93 per Bbl. The impact of the 2000 hedges decreased 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 impact of the 1999 hedges decreased 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's realized average oil price for 2001 (before hedges) was approximately 81 percent of the NYMEX reference price, compared to 91 percent in 2000 and 88 percent in 1999.

Average U.S. gas prices received by the Company fluctuate generally with changes in spot market prices, which may vary significantly by region, as evidenced by the significantly higher gas prices in California during the first half of 2001 due to the localized power shortage. The Company's Canada gas is generally sold at spot market prices as reflected by the AECO gas price index. 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. The Company's Argentina average gas price was historically determined primarily by the realized oil price from the El Huemul concession under a gas for oil exchange arrangement which expired at the end of 2001. Beginning in 2002, the Company's Argentina gas will be sold under spot contracts of varying lengths and, as a result of the emergency law enacted in January 2002, must now be paid in pesos as a result of the emergency law enacted in January 2002. This will initially result in a decrease in sales revenue value when converted to U.S. dollars due to the devaluation of the peso and current market conditions. This value may improve over time as domestic Argentina gas drilling declines and market conditions improve. The Company's total average gas price for 2001 was two percent higher than 2000 and 2000 was 70 percent higher than 1999.

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) covering approximately 2.2 MMBbls at a weighted average price of $23.77 per Bbl (NYMEX reference price) for various periods in the first half of 2002. The Company has also entered into various gas hedges (swap agreements) covering approximately 8.6 million MMBtu of its gas production over the period April through October 2002. The Canadian portion of the gas swap agreements (approximately 4.3 million MMBtu) is at the AECO gas price index reference price of 3.58 Canadian dollars per MMBtu and will be settled in Canadian dollars. The U.S. portion of the gas swap agreements (approximately 4.3 million MMBtu) is at a NYMEX reference price of $2.60 per MMBtu. Additionally, the Company has entered into basis swap agreements for the approximately 4.3 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. For additional information, see "Items 1 and 2. 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 2001 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 $13.7 million and $21.5 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 $4.6 million and $7.5 million, respectively, based on 2001 gas production.

Period to Period Comparison

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

During December 2000 and May 2001, the Company made two acquisitions which significantly impacted the period to period comparison for the year ended December 31, 2001, compared to the year ended December 31, 2000. These acquisitions (the "Canadian Acquisitions") include the purchase of 100 percent of the outstanding common stock of Cometra Energy (Canada) Ltd. (the "Cometra Acquisition") in December 2000 and the purchase of 100 percent of the outstanding common stock of Genesis Exploration Ltd. (the "Genesis Acquisition") in May 2001. The Company's consolidated revenues and expenses for the year ended December 31, 2001, include, under the purchase method of accounting, the consolidation of the revenues and expenses of Genesis for the last eight months of 2001.

The Company reported net income of $133.5 million for the year ended December 31, 2001, compared to net income of $195.9 million for the same period in 2000. An increase in the Company's oil and gas production of 20 percent on an equivalent barrel basis was substantially offset by a 14 percent reduction in average oil prices and higher charges for depreciation, depletion and amortization of oil and gas properties and goodwill. Net income for 2001 included a $17.9 million after-tax loss due to the impairment of oil and gas properties, a $16.7 million after-tax gain on sales of non-strategic properties and a $3.3 million after-tax gain due to the devaluation of the Argentine peso in December 2001. Net income for 2000 included a $16.3 million after-tax non-recurring charge due to an adverse judgment from litigation, a $1.1 million after-tax loss on sales of non-strategic properties and a $1.4 million after-tax loss due to a change in accounting principle.

Oil and gas sales increased $51.0 million (eight percent), to $731.4 million for 2001 from $680.4 million for 2000. A 41 percent increase in gas production, partially offset by a two percent decrease in average gas prices, accounted for a $76.6 million increase in gas sales for 2001 as compared to 2000. A 14 percent decrease in average oil prices more than offset an 11 percent increase in oil production and accounted for a $25.6 million decrease in oil sales for 2001 as compared to 2000. The 11 percent increase in oil production and the 41 percent increase in gas production are primarily the result of the Canadian Acquisitions and the Company's exploitation and exploration activities, partially offset by declines in U.S. production.

A gain on disposition of assets of $26.9 million ($16.7 million net of tax) was reflected in 2001 as a result of $47.1 million in proceeds from divestitures of non-strategic oil and gas properties in the United States. In 2000, the Company recorded a loss on disposition of assets of $1.7 million ($1.1 million net of tax). Other than the gain recorded, the 2001 divestitures did not significantly affect the Company's 2001 results of operations as the majority of the divestitures occurred in the fourth quarter of 2001.

As discussed in Note 1 to the Company's consolidated financial statements included elsewhere in this Form 10-K, the Argentine government took actions which, in effect, caused the devaluation of the peso in early December 2001. The translation of peso-denominated balances at December 31, 2001, and peso-denominated transactions during December 2001 increased 2001 net income by approximately $3.3 million, consisting of a foreign currency exchange gain of approximately $2.3 million (included in other income (expense) on the statement of operations) and approximately $1.0 million in reductions of certain operating expenses. There was no such gain in 2000.

As a result of an unfavorable decision by the Supreme Court of Argentina, the Company had recorded as other expense in 2000 a non-recurring charge of $25.1 million ($16.3 million net of tax). No similar charge was incurred in 2001.

Lease operating expenses, including production taxes, increased $54.0 million (34 percent), to $213.6 million for 2001 from $159.6 million for 2000 primarily due to the 20 percent increase in production, increased lease power and fuels costs, higher costs for oilfield services and certain one-time repair costs in the U.S. Lease operating expenses per equivalent barrel produced increased 12 percent to $6.18 in 2001 from $5.54 for 2000. 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 35 cents and 36 cents to the reported lease operating expense per BOE in 2001 and 2000, respectively.

Exploration costs decreased $3.1 million (12 percent), to $22.1 million for 2001 from $25.2 million for 2000. During 2001, the Company's exploration costs included $12.2 million for unsuccessful exploratory drilling and lease impairments, primarily in North America, and $9.9 million for seismic and other geological and geophysical costs. Exploration costs for 2000 included $21.6 million for unsuccessful exploratory drilling, primarily in Bolivia, $2.9 million for leasehold impairments and $0.7 million for other geological and geophysical costs.

Impairments of oil and gas properties of $29.1 million ($17.9 million net of tax) were recognized in 2001, compared to $0.2 million of impairments in 2000, due primarily to reserve revisions on certain Canadian and U.S. properties. 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) indicate that the properties' carrying values may not be recoverable. If an impairment is indicated based on the Company's estimated future net revenues for total proved and risk-adjusted probable and possible 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 oil and 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. If future price expectations are reduced, it is possible that additional significant impairment provisions for oil and gas properties would be required. Also, the economic instability in Argentina could cause economic conditions that would result in future significant impairments for the Company's oil and gas properties in that country.

General and administrative expenses increased $9.4 million (23 percent), to $50.8 million for 2001 from $41.4 million for 2000 due primarily to costs associated with the Canadian operations acquired through the Canadian Acquisitions and personnel additions and consulting costs in conjunction with the Company's higher level of capital expenditures. General and administrative expenses per equivalent barrel produced increased slightly to $1.47 for 2001 from $1.44 for 2000.

Depreciation, depletion and amortization increased $68.8 million (69 percent), to $168.9 million for 2001 from $100.1 million for 2000, due primarily to the 20 percent increase in production on a BOE basis and the 43 percent increase in the average amortization rate per equivalent barrel produced from $3.33 in 2000 to $4.75 in 2001 primarily due to the Genesis Acquisition.

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis. In 2001, goodwill was amortized using the unit-of-production basis over the total proved reserves acquired and totaled approximately $11.9 million. There was no goodwill amortization recorded in 2000. The Company adopted the provisions of Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS No. 142") on January 1, 2002. Under SFAS 142, goodwill is no longer subject to amortization. Rather, goodwill is subject to at least an annual assessment for impairment by applying a fair-value based test. Management has not determined at this time if the adoption of SFAS No. 142 will have any other impact on the Company's financial position or results of operations. Management plans to engage an independent appraisal firm to perform an assessment of the fair value of its Canadian segment, which will be compared to the carrying value of the segment to determine whether any impairment existed on the date of adoption. Under the provisions of SFAS No. 142, the Company has six months from the time of adoption to have its appraisal completed.

Interest expense increased $16.3 million (34 percent), to $64.7 million for 2001 from $48.4 million for 2000, due primarily to a 60 percent increase in the Company's total average outstanding debt year over year, primarily due to the Canadian Acquisitions. This increase was partially offset as the Company's overall average interest rate decreased to 7.58 percent in 2001 as compared to 8.87 percent in 2000. This reduction resulted from lower rates on its floating-rate debt due to overall market reductions and a significant increase in its level of lower-cost floating-rate borrowings versus fixed rate debt.

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, 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 U.S. 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 primarily due to 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 25 cents and 36 cents 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 (seven 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.

Capital Expenditures

During 2001, the Company's total oil and gas capital expenditures were $891.4 million, including $560.1 million allocated to producing oil and gas properties as part of the Genesis Acquisition and $42.3 million for the acquisition of the La Ventana and Rio Tunuyan concessions in Argentina. In North America, the Company's non-acquisition oil and gas capital expenditures totaled $186.2 million, including $53.6 million for undeveloped leasehold as part of the acquisition of Genesis. Exploration activities accounted for $106.3 million of the North America capital expenditures with exploitation activities contributing $79.9 million. During 2001, the Company's international non-acquisition oil and gas capital expenditures totaled $98.0 million, consisting of $76.8 million in Argentina on exploitation activities, $11.4 million in Ecuador, principally on exploitation, and $5.7 million and $2.7 million on exploration projects in Trinidad and Yemen, respectively. The Company also spent another $1.4 million in other international areas.

As of December 31, 2001, the Company had total unproved oil and gas property costs of approximately $100.0 million consisting of undeveloped leasehold costs of $82.7 million, including $60.3 million in Canada, and exploratory drilling in progress of $17.3 million. Approximately $20.4 million of the unproved 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.

On May 2, 2001, the Company completed the Genesis Acquisition for total consideration of $617 million, including transaction costs and the assumption of the estimated net indebtedness of Genesis at closing (see Note 7 "Significant Acquisition" to the consolidated financial statements included elsewhere in this Form 10-K). The cash portion of the acquisition price was paid through advances under the Company's revolving credit facility and cash on hand.

40

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. The Company's preliminary capital expenditure budget for 2002 is currently set at $144 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)	2001	2000	1999
Acquisition of oil and gas reserves	$ 607,217	$ 91,448	$ 166,787
Drilling	135,620	121,911	46,280
Acquisition of undeveloped acreage and seismic	85,489	18,084	12,742
Workovers and recompletions	62,038	25,811	10,749
Other	1,024	419	927
Oil and gas capital expenditures	891,388	257,673	237,485
Acquisition and construction of gathering systems	1,256	299	680
Total	$ 892,644	$ 257,972	$ 238,165

Liquidity

Internally generated cash flow, the borrowing capacity under its revolving credit facility and its ability to adjust its level of capital expenditures 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. Since 1990, in conjunction with the purchase of substantial oil and gas assets, the Company has completed five public equity offerings as well as two public debt offerings and two Rule 144A debt offerings, which provided the Company with aggregate net proceeds of $843 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. 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.

On May 30, 2001, the Company issued $200 million of its 7 7/8% Senior Subordinated Notes due 2011 (the "7 7/8% Notes"). The 7 7/8% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after May 15, 2006. In addition, prior to May 15, 2004, the Company may redeem up to 35 percent of the 7 7/8% Notes with the proceeds of certain underwritten public offerings of the Company's common stock. The 7 7/8% Notes mature on May 15, 2011, with interest payable semiannually on May 15 and November 15 of each year. All of the net proceeds to the Company from the sale of the 7 7/8% Notes were used to repay a portion of the existing indebtedness under the Company's revolving credit facility.

Under the Second Amended and Restated Credit Agreement dated November 30, 2000, as amended, (the "Bank Facility"), certain banks have provided to the Company a $625 million unsecured revolving credit facility. The Bank Facility establishes a borrowing base 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 facility size or the borrowing base.

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 December 31, 2001, the Company had $411.4 million outstanding under its Bank Facility, excluding outstanding letters of credit of approximately $12.3 million. As of February 28, 2002, 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 3.36 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.

The Company's unused availability under the Bank Facility at February 28, 2002, was approximately $200 million; however, the borrowing base is currently under review by the banks. Due to lower oil and gas price expectations by the banks and the economic instability in Argentina, the Agent and Syndication Agent banks have recommended a new borrowing base of $550 million, with security provided by the Company on certain assets. This recommendation is pending approval of 75 percent of the banks in the syndicate. If approved, the Company will have approximately $124 million available under the Bank Facility. 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 next borrowing base redetermination will be in May 2002.

The Company's internally generated cash flow, results of operations and financing for its operations are dependent on oil and gas prices. For 2001, approximately 64 percent of the Company's production was oil. Realized oil prices for the year decreased by 14 percent as compared to 2000. This decline in prices substantially offset an increase in total production on a BOE basis of 20 percent. 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. To the extent oil prices continue to decline, the Company's earnings and cash flow from operations may be adversely impacted. Continued low oil and gas prices could cause the Company to not be in compliance with maintenance covenants under its Bank Facility and could negatively affect its credit statistics and coverage ratios and thereby affect its liquidity.

Inflation

In recent years inflation has not had a significant impact on the Company's operations or financial condition. However, industry specific inflationary pressures built up in late 2000 and in 2001 due to favorable conditions in the industry. While oil and gas prices have recently declined, the cost of services in the oil and gas industry have not declined by a similar percentage. Any increases in product prices could cause inflationary pressures specific to the industry to also increase.

As a result of the recent devaluation of the peso, the Company expects inflationary pressures to build in Argentina. The Company anticipates that peso-denominated costs will gradually increase, but the ultimate impact of such increases when converted to U.S. dollars cannot be determined due to the uncertainty of future currency exchange rates.

Income Taxes

The Company incurred a current provision for income taxes of approximately $80.5 million, $68.9 million and $6.0 million for 2001, 2000 and 1999, respectively. 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 has been 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 fully utilized its U.S. federal regular tax net operating loss ("NOL") carryforward in 2000 and its U.S. federal alternative minimum tax credit carryforward in 2001. The Company has a Bolivian income tax NOL carryforward of approximately $57 million that does not expire and an Ecuadorian income tax NOL of approximately $5 million that expires in varying annual amounts over a five-year period beginning in 2002, both of which can be used to offset its future income tax liabilities. In addition to its NOL carryforward in Ecuador, the Company also has a $22.6 million deferred devaluation loss carryforward that is available to offset future taxable income. No asset has been recorded for this loss carryforward, which expires in 2009. The income tax benefit will be recorded in the period in which the loss carryforward is utilized. At December 31, 2001, the Company also had an Argentine income tax NOL of approximately 91 million pesos ($55 million) from its recently acquired subsidiary, Vintage Petroleum Argentina S.A., that expires in varying annual amounts over a five-year period beginning in 2002 and can be used to offset future income tax liabilities.

Critical Accounting Policies and Estimates

Management's discussion and analysis of its financial condition and results of operations are based upon the Company's consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). The preparation of these consolidated financial statements 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. The Company bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions. Note 1 to the Company's consolidated financial statements included elsewhere in this Form 10-K, contains a comprehensive summary of the Company's significant accounting policies. The following is a discussion of the Company's most critical accounting policies, judgments and uncertainties that are inherent in the Company's application of GAAP:

Proved reserve estimates. Estimates of the Company's proved reserves included in its consolidated financial statements and elsewhere in this Form 10-K are prepared in accordance with guidelines established by GAAP and by the SEC. The accuracy of a reserve estimate is a function of: (i) the quality and quantity of available data; (ii) the interpretation of that data; (iii) the accuracy of various mandated economic assumptions; and (iv) the judgment of the persons preparing the estimate.

The Company's proved reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be higher or lower than these estimates. Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of oil and gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate.

The present value of future net cash flows should not be assumed to be the current market value of the Company's estimated proved reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves were based on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

The estimates of proved reserves materially impact depletion, depreciation and amortization expense. If the estimates of proved reserves decline, the rate at which the Company records depletion, depreciation and amortization expense increases, reducing net income. Such a decline may result from lower market prices, which may make it uneconomic to drill for and produce higher cost reserves. In addition, the decline in proved reserve estimates may impact the outcome of the Company's assessment of its oil and gas producing properties for impairment.

Impairment of proved oil and gas properties. 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 and risk-adjusted probable and possible 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, consistent with methods used for acquisition evaluations.

As discussed in Note 12 to the Company's consolidated financial statements included elsewhere in this Form 10-K, in February 2002, the Argentina government also imposed a 20 percent excise tax on oil exports, effective March 1, 2002. This tax is limited by law to a term of no more than five years. Had this export tax been in effect at December 31, 2001, it would not have had a material impact on the Company's assessment of impairment of its oil and gas properties in Argentina.

Impairment of unproved oil and gas properties. Unproved leasehold costs are capitalized and are reviewed periodically for impairment. Costs related to impaired prospects are charged to expense. An impairment expense could result if oil and gas prices decline in the future as it may not be economic to develop some of these unproved properties.

Impairment of goodwill. The Company assesses the recoverability of goodwill by determining whether the net book value of the goodwill can be recovered through the aggregate of the excess of undiscounted future net revenues of the acquired properties over the net book value of those properties. The amount of goodwill impairment, if any, is measured based on fair value, which is defined as projected discounted future net revenues. The assessment of the recoverability of goodwill will be impacted if estimated future net revenues are not achieved. See "New Accounting Pronouncements" for discussion of the policy change that the Company adopted in 2002.

Revenue recognition. Revenue is a key component of the Company's results of operations and also determines the timing of certain expenses, such as severance taxes and royalties. The Company follows a very specific and detailed guideline of recognizing revenues when oil and gas are delivered to the purchaser. However, certain judgments affect the application of the Company's revenue recognition policy. Revenue results are difficult to predict, and any shortfall in revenue or delay in recognizing revenue could cause the Company's operating results to vary significantly from quarter to quarter and could result in future operating losses.

Income taxes. The Company provides deferred income taxes on transactions which are recognized in different periods for financial and tax reporting purposes. The Company has not recognized a U.S. deferred tax liability related to the unremitted earnings of any of its foreign subsidiaries as it is the Company's intention, generally, to reinvest such earnings permanently. The Company has also recorded deferred tax assets related to operating loss and tax credit carryforwards. Management periodically assesses the probability of recovery of recorded deferred tax assets based on its assessment of future earnings outlooks by tax jurisdiction. Such estimates are inherently imprecise since many assumptions are utilized in the assessments that may prove to be incorrect in the future.

Assessments of functional currencies. All of the Company's subsidiaries use the U.S. dollar as their functional currency, except for the Company's Canadian subsidiaries, which use the Canadian dollar. Management determines the functional currencies of the Company's subsidiaries based on an assessment of the currency of the economic environment in which a subsidiary primarily realizes and expends its operating revenues, costs and expenses. The assessment of functional currencies can have a significant impact on periodic results of operations and financial position.

Argentina economic and currency measures. The accounting for and translation of the Company's Argentina balance sheet as of December 31, 2001, reflects management's assumptions regarding some uncertainties unique to Argentina's current economic situation. See Note 1 to the Company's consolidated financial statements included elsewhere in this Form 10-K, for a description of the assumptions utilized in the preparation of these consolidated financial statements. The Argentina economic and political situation continues to evolve and the Argentine government may enact future regulations or policies that, when finalized and adopted, may materially impact, among other items, (i) the realized prices the Company receives for oil and gas it produces and sells as a result of export taxes; (ii) the timing of repatriations of cash to the U.S.; (iii) the Company's asset valuations; and (iv) peso-denominated monetary assets and liabilities. For further information, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in this Form 10-K.

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 (the "FASB") 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 statement of operations. 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 $18.5 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 increase to accumulated other comprehensive income in the Stockholders' Equity section of the balance sheet of approximately $14.9 million. The amount recorded to accumulated other comprehensive income was taken to the statement of operations as the physical transactions being hedged were finalized. All of the Company's cash flow hedges in place at January 1, 2001, had settled as of December 31, 2001, with the actual cash flow impact recorded in oil and gas sales in the Company's statement of operations.

New Accounting Pronouncements

On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, Business Combinations ("SFAS No. 141"), and SFAS No. 142. SFAS No. 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS No. 142, goodwill is no longer subject to amortization. Rather, goodwill will be subject to at least an annual assessment for impairment by applying a fair-value based test. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer's intent to do so. SFAS No. 142 is required to be applied starting with fiscal years beginning after December 15, 2001.

The Company's May 2001 acquisition of Genesis was accounted for using the purchase method of accounting. The Company adopted SFAS No. 142 effective January 1, 2002, resulting in the elimination of goodwill amortization from statements of operations in future periods. Management has not determined at this time if the adoption of SFAS No. 142 will have any other impact on the Company's financial position or results of operations. Management plans to engage an independent appraisal firm to perform an assessment of the fair value of its Canadian segment, which will be compared with the carrying value of the segment to determine whether any impairments existed on the date of adoption. Under the provisions of SFAS No. 142, the Company has six months from the time of adoption to have its appraisal completed.

In August 2001, the FASB issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. Currently the Company accrues future abandonment costs of wells and related facilities through its depreciation calculation and includes the cumulative accrual in accumulated depreciation. The new standard will require that the Company record the discounted fair value of the retirement obligation as a liability at the time a well is drilled or acquired. The liability will accrete over time with a charge to interest expense. The new standard will apply to financial statements for years beginning after June 15, 2002. While the new standard will require that the Company change its accounting for such abandonment obligations, the Company has not had an opportunity to evaluate the impact of the new standard on its financial statements.

In October 2001, the FASB issued Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets ("SFAS No. 144"). SFAS No. 144 sets forth accounting and reporting standards to establish a single accounting model, based on the framework established in Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, for long-lived assets to be disposed of by sale. The provisions of SFAS No. 144 are effective for financial statements issued for fiscal years beginning after December 15, 2001, and interim periods within those fiscal years, with early application encouraged. The provisions of SFAS No. 144 generally are to be applied prospectively. The Company does not believe that the adoption of SFAS No. 144 will have a material impact on its financial position or results of operations.

Foreign Operations

For information on the Company's foreign operations, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk" included elsewhere in 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of the impact of commodity price changes based on 2001 production levels. 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 various periods in 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 $0.7 million to terminate its oil swap agreements then in place.

During 2000, the Company entered into additional oil hedging contracts for various periods in 2000 covering an additional 7.5 MMBbls of oil and a weighted average NYMEX reference price of $27.94 per Bbl. 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 $30.71 per Bbl for various periods in 2001. At December 31, 2000, the Company would have received approximately $16.3 million to terminate its oil swap agreements then in place.

During 2001, the Company entered into additional oil hedging contracts for various periods in 2001 covering an additional 1.9 MMBbls of oil at a weighted average NYMEX reference price of $29.28 per Bbl. In total, the Company entered into oil hedging contracts covering 2001 production of 5.5 MMBbls of oil at a weighted average NYMEX reference price of $30.20 per Bbl. During 2001, the Company entered into various oil hedges (swap agreements) for a total of 0.9 MMBbls of oil at a weighted average NYMEX reference price of $25.54 per Bbl for various periods in 2002. At December 31, 2001, the Company would have received approximately $4.7 million to terminate its oil swap agreements then in place.

During 2002, the Company entered into additional oil hedging contracts for various periods in 2002 covering an additional 1.3 MMBbls of oil at a weighted average NYMEX reference price of $22.54 per Bbl. In total, the Company has entered into oil hedging contracts covering 2002 oil production of 2.2 MMBbls at a weighted average NYMEX reference price of $23.77 per Bbl. The Company has also entered into various gas hedges (swap agreements) covering approximately 8.6 million MMBtu of its gas production over the period April through October 2002. The Canadian portion of the gas swap agreements (approximately 4.3 million MMBtu) is at the AECO gas price index reference price of 3.58 Canadian dollars per MMBtu and will be settled in Canadian dollars. The AECO gas price index is the reference price used for most of the Company's Canadian gas spot sales. The U.S. portion of the gas swap agreements (approximately 4.3 million MMBtu) is at a NYMEX reference price of $2.60 per MMBtu. Additionally, the Company has entered into basis swap agreements for the approximately 4.3 million MMBtu of its U.S. gas production covered by the gas swap agreements. These basis swaps establish a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials received by the Company. 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, 2001, the amount of the Company's fixed rate debt was approximately 59 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.

Based on the outstanding borrowings under variable rate debt instruments at December 31, 2001, a change in the average interest rate of 100 basis points would result in a change in net income and cash flow before income taxes on an annual basis of approximately $2.5 million and $4.1 million, respectively.

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

	2002	2003	2004	2005	2006	There-after	Total
Long-Term Debt:							
Fixed rate (in thousands).....	-	-	-	$149,837	-	$449,436	$599,273
Average interest rate.........	-	-	-	9.0%	-	8.7%	8.8%
Variable rate (in thousands)..	-	-	-	$411,400	-	-	$411,400
Average interest rate.........	-	-	-	(a)	-	-	(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 1.25 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 Canada, Argentina, Bolivia, Ecuador, Yemen and Trinidad. For 2001, the Company's operations in Argentina accounted for approximately 27 percent of the Company's revenues, 39 percent of the Company's net operating profit (pre-tax income before impairments of oil and gas properties, goodwill amortization and general and administrative and interest expense) and 25 percent of its total assets. During 2001, the Company's operations in Argentina represented its only foreign operations accounting for more than 10 percent of its revenues or net operating profit (pre-tax income before impairments of oil and gas properties and general and administrative and interest expense). The Company's operations in Canada accounted for approximately 39 percent of its total assets, including goodwill, at December 31, 2001. The majority of these Canadian assets were purchased on May 2, 2001, as part of the acquisition of Genesis and the Company's exploration and production operations include only eight months of the operations of Genesis in 2001. At December 31, 2001, none of the Company's other international operations accounted for more than 10 percent of its 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.

Historically, the Company has not used derivatives or other financial instruments to hedge the risk associated with the movement in foreign currencies. However, the Company evaluates currency fluctuations and will consider the use of derivative financial instruments or employment of other investment alternatives if cash flows or investment returns so warrant.

The Company's international operations may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors. The Company's foreign properties, operations or investments in Canada, Argentina, Bolivia, Ecuador, Yemen and Trinidad may be adversely affected by a number of factors. For example:

- local political and economic developments could restrict or increase the cost of the Company's foreign operations;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive tax claims could increase costs of the Company's foreign operations;
- expropriation of the Company's property could result in loss of revenue, property and equipment;
- import and export regulations and other foreign laws or policies could result in loss of revenues; and
- laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict the Company's ability to fund foreign operations or may make foreign operations more costly.

The Company does not currently maintain political risk insurance. However, the Company will consider obtaining such coverage in the future if conditions so warrant.

Canada. With the acquisition of Cometra in December 2000 and the acquisition of Genesis in May 2001, the Company now has significant 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. 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. The US$:C$ exchange rate at December 31, 2001, was US$1:C$1.59 as compared to US$1:C$1.50 at December 31, 2000.

Argentina. Beginning in 1991, Peronist Carlos Menem, as newly-elected President of Argentina, and Domingo Cavallo, as his economy minister, set out to reverse economic decline through free-market reforms such as open trade. The key to their plan was the "Law of Convertibility" under which the peso was tied to the U.S. dollar at a rate of one peso to one U.S. dollar. Between 1991 and 1997 the plan succeeded. With the risk of devaluation apparently removed, capital came in from abroad and much of Argentina's state-owned assets were privatized. During this period, the economy grew at an annual average rate of 6.1 percent, the highest in the region.

However, the "convertibility" plan left Argentina with few monetary policy tools to respond to outside events. A series of external shocks began in 1998: prices for Argentina's commodities stopped rising; the dollar appreciated against other currencies; and Brazil, Argentina's main trading partner, devalued its currency. Argentina began a period of economic deflation, but failed to respond by reforming government spending. During 2001, Argentina's budget deficit exceeded $9 billion and its sovereign debt reached $140 billion.

As a result of economic instability and substantial withdrawals from the banking system, in early December 2001, the Argentine government instituted restrictions that prohibited foreign money transfers without Central Bank approval and prohibited cash withdrawals from bank accounts above a certain amount with certain limited exceptions. While the legal exchange rate remained at one peso to one U.S. dollar, financial institutions were allowed to conduct only limited activity due to these controls, and currency exchange activity was effectively halted except for personal transactions in small amounts. These actions by the government, in effect, caused a devaluation of the peso in

December 2001.

On January 6, 2002, the Argentine government enacted an emergency law that required certain contracts that were previously payable in U.S. dollars to be payable in pesos. U.S. dollars in Argentine banks on this date were converted to pesos at the government- imposed rate of 1.4 pesos to one U.S. dollar. Pursuant to the emergency law, U.S. dollar obligations between private parties due after January 6, 2002, are to be liquidated in pesos at a negotiated rate of exchange which reflects a sharing of the impact of the devaluation. The emergency law requires the obligor to make an interim payment of one peso per U.S. dollar of the claim and provides a period of 180 days for the parties to negotiate the final amount to settle the U.S. dollar obligation.

On February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. The Company currently exports approximately 35 percent of its Argentina oil production. However, management believes that this export tax will have the effect of decreasing all future Argentina oil revenues (not only export revenues) by the tax rate for the duration of the tax. Management believes that the U.S. dollar equivalent value for domestic Argentina oil sales (now paid in pesos) will move over time to parity with the U.S. dollar-denominated export values, net of the export tax, thus impacting domestic Argentina values by a like percentage to the tax. The adverse impact of this tax will be partially offset by the net cost savings resulting from the devaluation of the peso on peso-denominated costs and may be further reduced by the Argentina income tax savings related to deducting such impact. At December 31, 2001, the imposition of the export tax would not have had a material impact on the Company's assessment of impairment of its oil and gas properties in Argentina.

The Company continues to monitor the political and economic environment in Argentina. The Company's capital budgets have been adjusted to reflect a reduced level of drilling in the country. In addition, the devaluation of the peso is expected to result in a near-term reduction in revenues, substantially offset by a reduction in peso-denominated operating, administrative and capital costs, and the recognition of translation gains and losses, the impact of which cannot currently be accurately estimated.

Bolivia. 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 Bolivian 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.

The political environment in Bolivia has changed as President Hugo Banzer resigned and handed over power to his Vice-President, Jorge Quiroga. Mr. Quiroga, who is a U.S. educated industrial engineer, will run the country until new elections are held, which are currently scheduled for June 30, 2002. He will be barred from running in those elections due to term limits.

In 1987, 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, 2001, was US$1:Bs 7.12. 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.

Ecuador. In Ecuador, President Gustavo Noboa and Congress continue to debate further tax, social, and customs reforms to strengthen economic growth. The legal basis for many of the recent 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. Even though the second phase of the economic transformation law (known as Trole II), which was intended to bring significant tax and labor reform and a defined privatization program to increase inflows of foreign direct investment, was rejected by Congress, President Noboa used his veto powers to pass a tax reform package which allowed the International Monetary Fund ("IMF") to make a disbursement of its stand-by loan in the second quarter of 2001. Having met the fiscal targets in 2001 agreed to by the IMF, the government will be seeking further stand-by financing for 2002. Fixed investments significantly increased in 2001 as construction of the new heavy oil pipeline (the OCP) continues to progress on schedule.

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 2002 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."

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 because they are 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 Indenture dated as of May 30, 2001, between The Chase Manhattan Bank, as Trustee, and the Company (Filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4, Registration No. 333-63896).

4.6 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).

4.7	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 (Filed as Exhibit 10.15 to the Company's report on Form 10-K for the year ended December 31, 2000, filed March 12, 2001).
10.16	First Amendment to Second Amended and Restated Credit Agreement dated as of August 8, 2001, between the Company, the Lenders party thereto, Bank of Montreal, as administrative agent, Bank of America, N.A., as syndication agent, Societe General, Southwest Agency as documentation agent, and ABN AMRO Bank, N.V., as managing agent (Filed as Exhibit 10 to the Company's report on Form 10-Q for the quarter ended June 30, 2001, filed August 14, 2001).
10.17	Acquisition Agreement dated as of March 27, 2001, between the Company and Genesis Exploration Ltd. (Filed as Exhibit 2 to the Company's report on Form 8-K filed May 15, 2001).
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.
23.4	Consent of Outtrim Szabo Associates Ltd.
99.1	Letter to Commission Pursuant to Temporary Note 3T.

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* Management contract or compensatory plan or arrangement.

(b) Reports on Form 8-K.

No reports on Form 8-K were filed during the fourth quarter of the fiscal year ended December 31, 2001.

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 19, 2002

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 19,
/s/ S. Craig George S. Craig George	Director, President and Chief Executive Officer (Principal Executive Officer)	March 19,
/s/ William L. Abernathy William L. Abernathy	Director, Executive Vice President and Chief Operating Officer	March 19,
/s/ William C. Barnes William C. Barnes	Director, Executive Vice President, Chief Financial Officer, Secretary and Treasurer (Principal Financial Officer)	March 19,
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director	March 19,
/s/ Joseph D. Mahaffey Joseph D. Mahaffey	Director	March 19,
/s/ John T. McNabb, II John T. McNabb, II	Director	March 19,
/s/ Michael F. Meimerstorf Michael F. Meimerstorf	Vice President and Controller (Principal Accounting Officer)	March 19,

INDEX TO FINANCIAL STATEMENTS

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, 2001 and 2000, 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, 2001. 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, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the consolidated financial statements, effective January 1, 2001, the Company changed its method of accounting for derivatives to adopt the requirements of Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities.

ARTHUR ANDERSEN LLP

Tulsa, Oklahoma
February 13, 2002

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

A S S E T S

	December 31, 2001	December 31, 2000
CURRENT ASSETS:		
Cash and cash equivalents	$ 15,454	$ 19,506
Accounts receivable -		
Oil and gas sales	77,628	146,770
Joint operations	9,354	6,267
Derivative financial instruments receivable	4,701	--
Prepaids and other current assets	37,517	13,946
Total current assets	144,654	186,489
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method	2,498,552	1,734,003
Oil and gas gathering systems and plants	20,508	19,252
Other	25,506	19,636
	2,544,566	1,772,891
Less accumulated depreciation, depletion and amortization	809,522	667,837
	1,735,044	1,105,054
GOODWILL, net of amortization	156,990	--
OTHER ASSETS, net	60,100	46,854
	$ 2,096,788	$ 1,338,397

L I A B I L I T I E S A N D S T O C K H O L D E R S' E Q U I T Y

CURRENT LIABILITIES:		
Revenue payable	$ 25,625	$ 60,519

Accounts payable - trade	62,362	43,225
Current income taxes payable	21,638	43,187
Short-term debt	17,320	3,400
Other payables and accrued liabilities	45,200	61,961
Total current liabilities	172,145	212,292
LONG-TERM DEBT	1,010,673	464,229
DEFERRED INCOME TAXES	166,319	33,252
OTHER LONG-TERM LIABILITIES	18,208	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 shares authorized, 63,081,322 and 62,801,416 shares issued and outstanding	315	314
Capital in excess of par value	324,077	319,893
Retained earnings	428,443	303,449
Accumulated other comprehensive income (loss)	(21,632)	1,201
	731,203	624,857
Less unamortized cost of restricted stock awards	1,760	--
	729,443	624,857
	$ 2,096,788	$ 1,338,397

The accompanying notes are an integral part of these statements.

57

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	For the Years En	
	2001	20
REVENUES:		
Oil and gas sales	$ 731,386	$ 680
Gas marketing	130,209	128
Oil and gas gathering	17,032	19
Gain (loss) on disposition of assets	26,871	(1
Other income (expense)	3,743	(21
	909,241	806
COSTS AND EXPENSES:		
Lease operating, including production taxes	213,551	159

Exploration costs	22,073	25
Gas marketing	126,373	123
Oil and gas gathering	17,759	17
General and administrative	50,844	41
Depreciation, depletion and amortization	168,944	100
Impairment of oil and gas properties	29,050	
Amortization of goodwill	11,940	
Interest	64,728	48
	705,262	515
Income before income taxes and cumulative effect of change in accounting principle	203,979	290
PROVISION (BENEFIT) FOR INCOME TAXES:		
Current	80,535	68
Deferred	(10,063)	24
	70,472	92
Income before cumulative effect of change in accounting principle	133,507	197
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, net of income taxes of $644	--	(1
NET INCOME	$ 133,507	$ 195
BASIC INCOME PER SHARE:		
Income before cumulative effect of change in accounting principle	$ 2.12	$
Cumulative effect of change in accounting principle	--	(
Net income	$ 2.12	$
DILUTED INCOME PER SHARE:		
Income before cumulative effect of change in accounting principle	$ 2.09	$
Cumulative effect of change in accounting principle	--	(
Net income	$ 2.09	$
Weighted Average Common Shares Outstanding:		
Basic	63,023	62
Diluted	64,027	63

The accompanying notes are an integral part of these statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In thousands, except per share amounts)

Capital Unamortized

	Common Stock Shares	Common Stock Amount	In Excess of Par Value	Restricted Stock Awards	R E
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 ($.140 per share)	--	--	--	--	
BALANCE AT DECEMBER 31, 2000	62,801	314	319,893	--	
Comprehensive income:					
Transition adjustment for adoption of SFAS No. 133	--	--	--	--	
Net income	--	--	--	--	
Foreign currency translation adjustment	--	--	--	--	
Change in value of derivatives	--	--	--	--	
Total comprehensive income					
Exercise of stock options and resulting tax effects	170	1	1,970	--	
Issuance of restricted stock	110	--	2,214	(2,214)	
Amortization of restricted stock awards	--	--	--	454	
Cash dividends declared ($.135 per share)	--	--	--	--	
BALANCE AT DECEMBER 31, 2001	63,081	$ 315	$ 324,077	$ (1,760)	$

The accompanying notes are an integral part of these statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

	For the Years Ended Dece	
	2001	2000
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 133,507	$ 195,893
Adjustments to reconcile net income to cash provided by operating activities, net of companies acquired -		
Depreciation, depletion and amortization	168,944	100,109
Impairment of oil and gas properties	29,050	225
Amortization of goodwill	11,940	--
Exploration costs	22,073	25,242
Provision (benefit) for deferred income taxes	(10,063)	24,102
Cumulative effect of change in accounting principle	--	1,422
(Gain) loss on disposition of assets	(26,871)	1,731
Other non-cash items......................................	(1,215)	--
	327,365	348,724
Decrease (increase) in receivables	90,280	(56,179)
Increase (decrease) in payables and accrued liabilities ...	(95,789)	99,514
Income tax refund receivable	--	--
Other working capital changes.............................	(26,171)	3,628
Cash provided by operating activities	295,685	395,687
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures -		
Oil and gas properties	(269,328)	(209,552)
Gathering systems and other	(5,817)	(2,633)
Proceeds from sales of oil and gas properties	39,800	998
Purchase of companies, net of cash acquired	(478,158)	(46,199)
Other	(9,398)	(4,132)
Cash used by investing activities	(722,901)	(261,518)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Issuance of common stock	1,231	3,492
Issuance of 7 7/8% Senior Subordinated Notes Due 2011	199,930	--
Issuance of 9 3/4% Senior Subordinated Notes Due 2009	--	--
Advances on revolving credit facility and other borrowings	319,050	70,388
Payments on revolving credit facility and other borrowings	(88,431)	(224,343)
Dividends paid	(8,187)	(6,887)
Cash provided (used) by financing activities	423,593	(157,350)
EFFECT OF EXCHANGE RATE CHANGE ON CASH	(429)	--
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(4,052)	(23,181)
CASH AND CASH EQUIVALENTS, beginning of year	19,506	42,687

CASH AND CASH EQUIVALENTS, end of year	$ 15,454	$ 19,506

The accompanying notes are an integral part of these statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the Years Ended December 31, 2001, 2000 and 1999

1. Business and Significant Accounting Policies

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 99 percent of the Company's operations are within the exploration and production segment based on 2001 operating income before impairments of oil and gas properties, gains on asset sales and goodwill amortization. The Company's North American exploration and production operations include the West Coast, Gulf Coast, East Texas and Mid-Continent areas of the United States and the western sedimentary basins of Canada. The Company also has core areas of operations in the San Jorge Basin and Cuyo Basin of Argentina, the Chaco Basin in Bolivia and in Ecuador. The Company also has exploration activities currently ongoing in Yemen and Trinidad.

Consolidation and Presentation

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.

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 gains or losses 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. An impairment expense could result if oil and gas prices decline in the future as it may not be economic to develop some of these unproved properties.

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.

In August 2001, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. Currently the Company accrues future abandonment costs of wells and related facilities through its depreciation calculation and includes the cumulative accrual in accumulated depreciation. The new standard will require that the Company record the discounted fair value of the retirement obligation as a liability at the time a well is drilled or acquired. The liability will accrete over time with a charge to interest expense. The new standard will apply to financial statements for years beginning after June 15, 2002. While the new standard will require that the Company change its accounting for such abandonment obligations, the Company has not had an opportunity to evaluate the impact of the new standard on its financial statements.

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 from estimated future net revenues. 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 and risk-adjusted probable and possible 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, consistent with methods used for acquisition evaluations.

The Company recorded impairment provisions related to its proved oil and gas properties of $29.1 million, $0.2 million and $3.3 million in 2001, 2000 and 1999, respectively. Prior to 2001, the Company considered only proved oil and gas reserves in determining future net revenues and fair value. However, with the December 2000 acquisition of Cometra Energy (Canada), Ltd. ("Cometra") and, more significantly, the May 2001 acquisition of Genesis Exploration Ltd. ("Genesis"), the Company acquired what it considers to be substantial probable and possible oil and gas reserves in Canada. The potential value of these reserves, on a risk-adjusted basis, was considered in determining the value of oil and gas properties during the Company's acquisition analyses. As a result of the possibility of significant value attributable to the probable and possible reserves, the Company accordingly began to include the future net revenues and present value of risk-adjusted probable and possible reserves in its future net revenues for impairment and fair value determinations.

In estimating the future net revenues at December 31, 2001, to be used for impairment testing, the Company assumed that oil and 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.

In October 2001, the FASB issued Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets ("SFAS No. 144"). SFAS No. 144 establishes accounting and reporting standards to establish a single accounting model, based on the framework established in Statement of Financial Accounting Standards No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of, for long-lived assets to be disposed of by sale. The provisions of SFAS No. 144 are effective for financial statements issued for fiscal years beginning after December 15, 2001, and interim periods within those fiscal years, with early application encouraged. The provisions of SFAS No. 144 generally are to be applied prospectively. The Company does not believe that the adoption of SFAS No. 144 will have a material impact on its financial position or results of operations.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis (see Note 7). In 2001, goodwill was amortized using the unit-of-production basis over the total proved reserves acquired. Accumulated amortization was approximately $11.9 million at December 31, 2001. The Company assesses the recoverability of goodwill by determining whether the net book value of the goodwill can be recovered through the aggregate of the excess of undiscounted future net revenues of the acquired properties over the net book value of those properties. The amount of goodwill impairment, if any, is measured based on projected discounted future net revenues using a discount rate reflecting the Company's average cost of funds. The assessment of the recoverability of goodwill will be impacted if estimated future net revenues are not achieved.

On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, Business Combinations ("SFAS No. 141"), and Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets ("SFAS No. 142"). SFAS No. 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS No. 142, goodwill is no longer subject to amortization. Rather, goodwill will be subject to at least an annual assessment for impairment by applying a fair-value based test. Additionally, an acquired intangible asset should be separately recognized if the benefit of the intangible asset is obtained through contractual or other legal rights, or if the intangible asset can be sold, transferred, licensed, rented or exchanged, regardless of the acquirer's intent to do so. SFAS No. 142 is required to be applied starting with fiscal years beginning after December 15, 2001.

The Company's May 2001 acquisition of Genesis was accounted for using the purchase method of accounting. The Company adopted SFAS No. 142 effective January 1, 2002, resulting in the elimination of goodwill amortization from statements of operations in future periods. Management has not determined at this time if the adoption of SFAS No. 142 will have any other impact on the Company's financial position or results of operations. Management plans to engage an independent appraisal firm to perform an assessment of the fair value of its Canadian segment, which will be compared with the carrying value of the segment to determine whether any impairment exists on the date of adoption. Under the provisions of SFAS No. 142, the Company has six months from the time of adoption to have its appraisal completed.

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 the 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 5.5 MMBbls during 2001, the impact of which increased its U.S. average oil price by 91 cents to $23.08 per Bbl, its Argentina average oil price by $1.14 to $21.80 per Bbl, and its overall average oil price by 89 cents to $21.93 per Bbl. The Company participated in oil hedges covering 9.3 MMBbls during 2000, the impact of which reduced its 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 1.8 MMBbls during 1999, the impact of which reduced its 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.

In June 1998, the FASB 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 statement of operations. 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 $18.5 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 in the Stockholders' Equity section of the balance sheet of approximately $14.9 million. The amount recorded to accumulated other comprehensive income was relieved and taken to the statement of operations as the physical transactions being hedged were finalized. All of the Company's cash flow hedges in place at January 1, 2001, had settled as of December 31, 2001, with the actual cash flow impact recorded in oil and gas sales in the Company's statement of operations. At December 31, 2001, the Company had a derivative financial instrument receivable of $4.7 million related to 2002 cash flow hedges in place. During 2001, there were no significant gains or losses recognized in earnings for hedge ineffectiveness. The Company did not discontinue any hedges because of the probability that the original forecasted transaction would not occur.

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 from 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.

During the years ended December 31, 2001, 2000 and 1999, the Company made cash payments for interest totaling $58.6 million, $48.3 million and $56.8 million, respectively. Cash payments for U.S. income taxes of $24.1 million and $19.8 million were made during 2001 and 2000, respectively. No cash payments for U.S. income taxes were made during 1999. The Company made cash payments of $77.8 million and $9.5 million during 2001 and 2000 for foreign income taxes, primarily in Argentina. No cash payments were made during 1999 for foreign income taxes.

In December 2000, the Company purchased 100 percent of the outstanding common stock of Cometra. The 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.

In May 2001, the Company purchased 100 percent of the outstanding common stock of Genesis (see Note 7). The total purchase price included both cash and the assumption of $154.1 million in net liabilities. These net liabilities are not reflected in the Company's 2001 statement of cash flows.

Earnings Per Share

Basic earnings per common share were computed by dividing net income by the weighted average number of shares outstanding during the period. Diluted earnings per common share for 2001, 2000 and 1999 were computed assuming the exercise of all dilutive options, as determined by applying the treasury stock method. In addition, for the years ended December 31, 2001, 2000 and 1999, the Company had outstanding stock options for 3,244,400, 714,000 and 1,635,000 additional shares of the Company's common stock, respectively, with average exercise prices of $19.22, $20.19 and $17.70, respectively, which were antidilutive.

General and Administrative Expense

The Company receives fees for the operation of jointly-owned oil and gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $6.9 million, $4.2 million and $4.9 million in 2001, 2000 and 1999, respectively.

Lease Operating Expense

For the years ended December 31, 2001, 2000 and 1999, the Company recorded in lease operating expenses gross production taxes of $15.8 million, $17.4 million and $7.5 million, respectively, and transportation and storage expenses of $12.2 million, $10.5 million and $6.2 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 state-owned 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 subsidiaries, which use the Canadian dollar. Adjustments arising from translation of the Canadian subsidiaries' 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 its subsidiary's functional currency are included in the results of operations as incurred.

The Company's operations in Argentina represented approximately 35 percent of its 2001 total production and approximately 37 percent of the Company's total proved reserves at December 31, 2001.

Beginning in 1991, the Argentine peso ("peso") was tied to the U.S. dollar at a rate of one peso to one U.S. dollar. As a result of economic instability and substantial withdrawals from the banking system, in early December 2001, the Argentine government instituted restrictions that prohibited foreign money transfers without Central Bank approval and prohibited cash withdrawals from bank accounts above a certain amount with certain limited exceptions. While the legal exchange rate remained at one peso to one U.S. dollar, financial institutions were allowed to conduct only limited activity due to these controls, and currency exchange activity was effectively halted except for personal transactions in small amounts. These actions by the government in effect caused a devaluation of the peso in December 2001. On January 11, 2002, the foreign currency markets re-opened with the floating exchange rate closing at a range of 1.6 to 1.7 pesos to one U.S. dollar.

Because exchangeability of the peso was lacking from early December 2001 to January 11, 2002, the Company used the estimated exchange rate of 1.65 pesos to one U.S. dollar at January 11, 2002, (the first rate subsequent to year end at which exchanges could be made) to translate peso-denominated balances at December 31, 2001, and peso-denominated transactions during December 2001. This translation increased 2001 net income by approximately $3.3 million, consisting of a foreign currency exchange gain of approximately $2.3 million (included in other income (expense) on the statement of operations) and approximately $1.0 million in reductions of certain operating expenses during December 2001.

On January 6, 2002, the Argentine government enacted an emergency law that required certain contracts that were previously payable in U.S. dollars to be payable in pesos. U.S. dollars in Argentine banks on this date were converted to pesos at a rate of 1.4 pesos to one U.S. dollar. Pursuant to the emergency law, U.S. dollar obligations between private parties due after January 6, 2002, are to be liquidated in pesos at a negotiated rate of exchange which reflects a sharing of the impact of the devaluation. The emergency law requires the obligor to make an interim payment of one peso per U.S. dollar of the claim and provides a period of 180 days for the parties to negotiate the final amount to settle the U.S. dollar obligation.

Absent the January 6, 2002, emergency law, the devaluation of the peso would have had no effect on the U.S. dollar-denominated payables and receivables at December 31, 2001. Therefore, the effect of this involuntary conversion will be recorded in 2002 and the Company does not expect it to have a material effect on its financial position or results of operations.

The Company evaluated the effect of the recent events on its determination of the functional currency of its Argentina operations and it believes that its functional currency remains the U.S. dollar. Management believes that the recent changes in Argentina, some of which are expected to be temporary, do not represent a significant change in fact or circumstance sufficient to indicate a clear change in functional currency.

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 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 year 1999 has been restated to reflect the adoption of EITF 00-10. The adoption of EITF 00-10 did not impact net income.

Comprehensive Income

The Company applies the provisions of Statement of Financial Accounting Standards No. 130, Reporting Comprehensive Income ("SFAS No. 130"). The Company had a foreign currency translation loss of $25.8 million (net of $20.8 million tax benefit) for the year ended December 31, 2001, and a foreign currency translation gain of $1.2 million (net of $0.9 million tax expense) for the year ended December 31, 2000, which are included in accumulated other comprehensive income in the Stockholders' Equity section of the accompanying balance sheet. The Company had no non-owner changes in equity other than net income during the year ended December 31, 1999.

The Company also recorded under SFAS No. 133 a net reduction in unrealized derivative gains, of approximately $11.9 million (net of $4.1 million tax benefit) related to oil swaps, reducing the unrealized gains to $3.0 million (net of $1.9 million tax expense) included in accumulated other comprehensive income at December 31, 2001. This net reduction consisted of the removal of the $14.9 million (net of $6.0 million tax expense) transitional asset established on January 1, 2001, for contracts in place at December 31, 2000, all of which settled in 2001, and an increase for a current period change in value of $3.0 million for contracts to be settled in the first half of 2002. The actual cash flow impact of settled oil swaps of $19.7 million, including oil swaps entered into during 2001, has been reflected in the oil and gas sales line on the Company's statement of operations for the year ended December 31, 2001.

2. Long-Term Debt

Long-term debt at December 31, 2001 and 2000, consisted of the following:

(In thousands)	2001	2000
Revolving credit facility..........................	$ 411,400	$ 65,000
Senior subordinated notes:		
9% Notes due 2005, less unamortized discount.......	149,837	149,796
8 5/8% Notes due 2009, less unamortized discount...	99,503	99,433
9 3/4% Notes due 2009..............................	150,000	150,000
7 7/8% Notes due 2011, less unamortized discount...	199,933	-
	$ 1,010,673	$ 464,229

The Company has no long-term debt maturities prior to November 30, 2005. A total of $561.2 million of debt matures in 2005 and all other debt matures in 2009 or later. The Company had $9.5 million and $5.0 million of accrued interest payable related to its long- term debt at December 31, 2001 and 2000, 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, as amended (the "Bank Facility"), between the Company and certain banks. The Bank Facility establishes a borrowing base ($850 million at December 31, 2001) 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 $625 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, 2001, were $411.4 million at an average interest rate of approximately 3.95 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 August 2001. If the sum of outstanding senior debt exceeds the borrowing base, as redetermined, the Company must repay such excess. Any principal advances outstanding are due at maturity on November 30, 2005.

The Company had $12.3 million in letters of credit outstanding at December 31, 2001. 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 Bank Facility is reduced by the outstanding letters of credit.

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. The 9 3/4% Notes mature on June 30, 2009, with interest payable semiannually on June 30 and December 30 of each year. All of the net proceeds to the Company from the sale of the 9 3/4% Notes (approximately $146.0 million) were used to repay a portion of the existing indebtedness under the Company's Bank Facility.

On May 30, 2001, the Company issued $200 million of its 7 7/8% Senior Subordinated Notes due 2011 (the "7 7/8% Notes"). The 7 7/8% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after May 15, 2006. In addition, prior to May 15, 2004, the Company may redeem up to 35 percent of the 7 7/8% Notes with the proceeds of certain underwritten public offerings of the Company's common stock. The 7 7/8% Notes mature on May 15, 2011, with interest payable semiannually on May 15 and November 15 of each year. All of the net proceeds to the Company from the sale of the 7 7/8% Notes (approximately $199.9 million) were used to repay a portion of the existing indebtedness under the Company's Bank Facility.

The 9% Notes, 8 5/8% Notes, 9 3/4% Notes and 7 7/8% 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 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 existing indebtedness under the Company's Bank Facility.

Stock Plans

The Company has two fixed plans which reserve shares of common stock for issuance to key employees and 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 for stock options granted has been recognized. Had compensation cost for these plans been determined consistent with the provisions of SFAS No. 123, the Company's net income and earnings per share would have been adjusted to the following pro forma amounts:

(In thousands, except per share amounts)	2001	2000	1999
Net income - as reported	$133,507	$ 195,893	$ 73,371
Net income - pro forma	129,237	193,252	71,130
Earnings per share - as reported:			
Basic	2.12	3.13	1.27

Diluted................................	2.09	3.06	1.24
Earnings per share - pro forma:			
Basic..................................	2.05	3.08	1.23
Diluted................................	2.02	3.02	1.20

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 2001 include a dividend yield of 0.7 percent, expected volatility of approximately 49.1 percent, a risk-free interest rate of approximately 4.7 percent and expected lives of 4.5 years. 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.

Under the 1990 Stock Plan, as amended (the "1990 Plan"), 10 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, is 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, 2001, awards for a total of 466,946 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, 2001, options for a total of 16,000 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 2001, 2000 and 1999:

	2001		2000		19
	Shares	Wtd. Avg. Exercise Price	Shares	Wtd. Avg. Exercise Price	Shares
Beginning stock options outstanding..	5,026,592	$13.16	4,616,142	$11.61	3,606,142
Stock options granted	1,038,000	20.87	853,000	19.62	1,070,000
Stock options canceled	(179,500)	18.53	(49,000)	13.70	--
Stock options exercised	(169,906)	7.24	(393,550)	8.87	(60,000)
Ending stock options outstanding	5,715,186	$14.57	5,026,592	$13.16	4,616,142
Ending stock options exercisable	2,869,131	$13.47	2,238,142	$10.89	1,967,256
Weighted average fair value of options granted	$ 9.09		$ 9.02		$ 2.24

Of the 5,715,186 options outstanding at December 31, 2001: (a) 2,230,536 options have exercise prices between $5.94 and $9.81, with a weighted average exercise price of $8.27 and a weighted average contractual life of 5.0 years (1,219,536 of these options are exercisable currently at a weighted average price of $9.11); (b) 992,150 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 4.7 years (952,150 of these options are exercisable currently at a weighted average price of $14.24); and (c) 2,492,500 options have exercise prices between $16.06 and $22.94, with a weighted average exercise price of $20.33 and a weighted average contractual life of 7.5 years (697,445 of these options are exercisable currently at a weighted average price of $20.05).

All of the outstanding options are exercisable at various times in years 2002 through 2011. All incentive stock options and non- qualified stock options were granted at fair market value on the date of grant. Generally, options granted under the 1990 Plan have a 10-year term and provide for vesting over three years.

In addition to the above option activity, the Company has granted under the 1990 Plan 110,000 shares of restricted stock to employees during 2001. All of the shares vest over a three-year period. The related compensation expense of $2.2 million (based on the stock price on the date of grant) is being amortized over the vesting periods and during 2001 the Company recorded compensation expense of $0.5 million. As of December 31, 2001, none of the shares have vested to employees.

At December 31, 2001, a total of 6,198,132 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, 2001, consisted 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 Yemen. In Ecuador, the Company is committed to drill two wells in Block 14 at an estimated cost of approximately $4.2 million each and two wells in Block 17 at an estimated cost of approximately $3.2 million each in 2002 and is committed to drill one well in the Shiripuno Block in 2003 at an estimated cost of approximately $4.2 million. The Company is also committed to drill one well in the Chaco concession in Bolivia in 2003 at an estimated cost of approximately $6.3 million.

Through its December 2000 acquisition of 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. As of December 31, 2001, the Company had fulfilled the seismic requirements and had drilled two of the three exploratory wells.

The Company had $12.3 million in letters of credit outstanding at December 31, 2001. 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 Bank Facility is reduced by the outstanding letters of credit.

Rent expense was $2.9 million, $2.3 million and $1.8 million for 2001, 2000 and 1999, respectively. The future minimum commitments under long-term, non-cancellable leases for office space are $2.7 million, $2.7 million, $2.8 million, $4.4 million and $2.0 million for the years 2002 through 2006, respectively, with $0.8 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 Aires, 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 charge to "Other expense" in the second quarter of 2000 for 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 million pesos ($600,000) 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 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 counterparties 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 counterparties with appropriate credit standings.

At December 31, 2001, the Company was a party to oil price swap agreements for various periods of 2002 covering 0.9 MMBbls at a weighted average NYMEX reference price of $25.54 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 (see Note 2) 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, 2001 and 2000, was $1.02 billion and $475.2 million, respectively, compared with a carrying value of $1.01 billion and $464.2 million, respectively.

The fair value of commodity swap agreements is the amount at which they could be settled, based on quoted market prices. At December 31, 2001 and 2000, the Company would have received approximately $4.7 million and $16.3 million, respectively, 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 before income taxes and cumulative effect of change in accounting principle is composed of the following:

(In thousands)	2001	2000	1999
Domestic	$117,240	$123,951	$ 33,097
Foreign	86,739	166,324	64,603
	$203,979	$290,275	$ 97,700

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

(In thousands)	2001	2000	1999
Current:			
Domestic	$ 46,486	$ 17,053	$ 1,036
Foreign	34,049	51,805	4,918
Deferred:			
Domestic	(2,087)	32,460	11,730
Foreign	(7,976)	(8,358)	6,645
	$ 70,472	$ 92,960	$ 24,329

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

	2001	2000	1999
U.S. federal statutory income tax rate	35.0%	35.0%	35.0%
State income tax	3.9	3.9	3.9
Foreign operations	(3.8)	(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	(0.8)	--	(0.1)
Other	0.2	(0.1)	--
	34.5%	32.0%	24.9%

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The components of the Company's net deferred tax liability as of December 31, 2001 and 2000, are as follows:

(In thousands)	2001	2000
Deferred Tax Assets:		
U.S. federal and state net operating loss carryforwards.....	$ 1,073	$ 976
Foreign NOL carryforwards..................................	34,724	16,291
Foreign tax credit carryforwards...........................	3,559	-
Other temporary book/tax differences.......................	3,385	7,832
	42,741	25,099
Deferred Tax Liabilities:		
Book/tax differences in property basis.....................	201,367	58,057
Other temporary book/tax differences.......................	7,693	294
	209,060	58,351
Net deferred tax liability.............................	$ 166,319	$ 33,252

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") carryforward of approximately $57 million that does not expire and an Ecuadorian income tax NOL carryforward of approximately $5 million that expires in varying annual amounts over a five-year period beginning in 2002, both of which can be used to offset its future income tax liabilities. In addition to its NOL in Ecuador, the Company also has a $22.6 million deferred devaluation loss carryforward that is available to offset future taxable income. No asset has been recorded for this loss carryforward, which expires in 2009. The income tax benefit will be recorded in the period in which the loss carryforward is utilized. The Company also has an Argentine income tax NOL at December 31, 2001, of approximately 91 million pesos ($55 million) in its recently acquired subsidiary, Vintage Petroleum Argentina S.A., that expires in varying annual amounts over a five-year period beginning in 2002 and can be used to offset future income tax liabilities.

The Company fully utilized its U.S. federal regular tax NOL carryforward in 2000, and its alternative minimum tax credit carryforward in 2001. 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. Significant Acquisition

On May 2, 2001, the Company completed the acquisition of Canadian-based Genesis for total consideration of $617 million, including transaction costs and the assumption of the estimated net indebtedness of Genesis at closing (the

"Genesis Acquisition"). The cash portion of the acquisition price was paid through advances under the Company's revolving credit facility and cash on hand. The Genesis Acquisition was accounted for using purchase accounting and, as such, only eight months of Genesis activity are included in the Company's statement of operations for the year ended December 31, 2001.

The Company acquired 62.1 million barrels of oil equivalent ("BOE") of proved reserves in the transaction with Genesis, consisting of approximately 27.5 MMBbls of oil and 207.7 Bcf of gas. Proved undeveloped reserves of oil and gas account for 33 percent of the total proved reserves acquired. In addition, the Company estimates that the properties have significant upside potential which may be realized through its 2002 work program and beyond. The reserves acquired in the Genesis Acquisition are located primarily in the provinces of Alberta and Saskatchewan, with significant exploration exposure in the Northwest Territories.

In addition to reserves, the Company acquired over one million net undeveloped acres located in Alberta and Saskatchewan along with a significant portion, aggregating to 440,000 net acres, in the Northwest Territories. The Company estimates the acquisition cost of proved reserves was approximately $9.06 per BOE, exclusive of $54 million allocated to undeveloped acreage.

The Genesis Acquisition purchase price was allocated as of May 2, 2001, as follows (in thousands):

	C$	US$ (a)
Total purchase price	$ 944,423	$ 616,866
Long-term debt assumed	(135,000)	(88,178)
Negative working capital assumed	(100,854)	(65,874)
Amount paid	708,569	462,814
Net assets at May 2, 2001	(221,000)	(144,350)
Excess of purchase price over net assets at May 2, 2001	$ 487,569	$ 318,464
Allocation of excess of purchase price over net assets:		
Fair market value adjustment to oil and gas properties	$ 394,584	$ 257,729
Goodwill	268,763	175,547
Increase in deferred income taxes	(170,347)	(111,265)
Increase in accrued liabilities	(5,431)	(3,547)
	$ 487,569	$ 318,464

(a) Converted at the May 2, 2001, exchange rate of US$1/C$1.5310.

The Company has not yet completed its final evaluation of the assets acquired and the liabilities assumed. Therefore, the purchase price allocation is subject to change.

If the Genesis Acquisition had been consummated as of January 1, 2000, the Company's unaudited pro forma revenues and net income for the years ended December 31, 2001 and 2000, would have been as shown below; however, such pro forma information is not necessarily indicative of what actually would have occurred had the transaction occurred on such date.

	2001	20
	(In thousands, ex per share amoun	
Revenues	$ 968,031	$ 93
Income before cumulative effect of change in accounting principle	131,117	17
Net income	131,117	17
Basic Income Per Share:		
Income before cumulative effect of change in accounting principle	$ 2.08	$
Net income	2.08	
Diluted Income Per Share:		
Income before cumulative effect of change in accounting principle	$ 2.05	$
Net income	2.05	

8. 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 below and on the following page.

	Exploration and Productio

2001 (in thousands)	U.S.	Canada	Argentina	Bolivia
Revenues from external customers................	$ 386,344	$ 86,274	$ 243,329	$ 17,64
Intersegment revenues..........................	-	-	-	
Depreciation, depletion and amortization expense.	60,426	52,072	44,252	5,03
Impairment of oil and gas properties............	9,555	18,895	600	
Segment operating income (loss).................	196,894	(34,845)	137,459	8,23
Total assets....................................	477,415	818,564	530,201	119,65
Capital investments.............................	61,821	689,308	119,105	1,03
Long-lived assets...............................	436,327	795,000	475,418	93,57

2001 (in thousands)	Gathering/ Plant	Gas Marketing	Corporate	Total
Revenues from external customers................	$ 17,032	$ 130,209	$ 4,108	$ 909,24
Intersegment revenues..........................	-	1,968	-	1,96
Depreciation, depletion and amortization expense.	1,326	-	2,902	168,94
Impairment of oil and gas properties............	-	-	-	29,05
Segment operating income (loss).................	(2,053)	3,836	1,206	319,55
Total assets....................................	8,456	8,459	46,384	2,096,78
Capital investments.............................	1,256	-	5,870	898,51
Long-lived assets...............................	5,798	-	7,847	1,892,03

	Exploration and Productio			
2000 (in thousands)	U.S.	Canada	Argentina	Bolivia
Revenues from external customers................	$ 346,574	$ 2,281	$ 256,234	$ 19,53
Intersegment revenues..........................	-	-	-	
Depreciation, depletion and amortization expense.	53,184	586	33,077	7,42
Impairment of oil and gas properties............	225	-	-	
Segment operating income (loss).................	192,508	1,001	170,301	(3,79
Total assets....................................	524,588	60,274	459,219	126,39
Capital investments.............................	64,124	52,788	92,885	28,74
Long-lived assets...............................	477,198	55,626	401,702	97,52

2000 (in thousands)	Gathering/ Plant	Gas Marketing	Corporate	Total
Revenues from external customers................	$ 19,998	$ 128,836	$ 2,110	$ 806,18
Intersegment revenues..........................	2,080	2,372	-	4,45

Depreciation, depletion and amortization expense.	1,567	-	2,207	100,10
Impairment of oil and gas properties............	-	-	-	22
Segment operating income (loss).................	1,380	5,049	(98)	380,12
Total assets....................................	13,479	35,977	47,208	1,338,39
Capital investments.............................	299	-	2,334	260,30
Long-lived assets...............................	5,862	-	4,940	1,105,05

	Exploration and Production			
1999 (in thousands)	U.S.	Argentina	Bolivia	Ecuador
Revenues from external customers................	$ 275,486	$ 142,374	$ 5,786	$ 10,31
Intersegment revenues...........................	-	-	-	
Depreciation, depletion and amortization expense.	70,520	29,496	2,380	1,32
Impairment of oil and gas properties............	3,306	-	-	
Segment operating income (loss).................	112,902	77,033	(1,289)	6,71
Total assets....................................	520,443	379,099	107,847	59,63
Capital investments.............................	51,571	131,551	30,789	16,09
Long-lived assets...............................	476,153	342,179	88,292	49,85

1999 (in thousands)	Gathering/ Plant	Gas Marketing	Corporate	Total
Revenues from external customers................	$ 6,955	$ 60,275	$ 1,736	$ 502,92
Intersegment revenues...........................	1,350	1,285	-	2,63
Depreciation, depletion and amortization expense.	1,400	-	2,688	107,80
Impairment of oil and gas properties............	-	-	-	3,30
Segment operating income (loss).................	402	2,725	(952)	192,77
Total assets....................................	6,372	6,601	81,610	1,168,13
Capital investments.............................	680	-	1,989	240,15
Long-lived assets...............................	3,629	-	4,718	971,35

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 2001, sales to two crude oil purchasers of the exploration and production segment represented approximately 12 percent and 11 percent, respectively, of the Company's total revenues (exclusive of eliminations of intersegment sales, the impact of hedges and $26.9 million of gains on the sale of oil and gas properties). 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 gains on the sales of oil and gas properties).

9. Detail of Prepaids and Other Current Assets

(In thousands)	2001	2000
Property divestiture proceeds receivable.....	$ 7,287	$ -
Other prepaids and current assets...........	30,230	13,946
	$ 37,517	$ 13,946

10. Quarterly Results (Unaudited)

The following is a summary of the quarterly results of operations for the years ended December 31, 2001 and 2000. 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)	Quarter Ended			
	Mar. 31	Jun. 30	Sept. 30	Dec
2001(c)				
Revenues..	$ 275,490	$ 251,914	$ 193,823	$ 1
Operating income....................................	120,180	99,829	27,834	
Provision (benefit) for income taxes................	38,565	31,736	1,725	
Net income..	70,698	52,219	6,242	
Income per share:				
Basic...	1.12	.83	.10	
Diluted.......................................	1.10	.81	.10	
2000				
Revenues..	$ 162,391	$ 156,266(b)	$ 229,981	$ 2
Operating income....................................	73,701	53,783(b)	100,995	1
Cumulative effect of change in accounting principle..	(1,422)	-	-	
Provision for income taxes..........................	20,580	14,800	30,837	
Net income..	38,284(a)	27,059(b)	58,548	
Income per share:				
Basic...	.61(a)	.43(b)	.93	
Diluted.......................................	.60(a)	.42(b)	.92	

(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) The quarters ended June 30, 2001, September 30, 2001, and December 31, 2001 include the results of Genesis (see Note 7).

11. 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, 2001, 2000 and 1999. The Company began operations in Canada in December 2000.

	2001				
(In thousands)	U.S.	Canada	Argentina	Bolivia	Ecuado
Revenues	$359,471	$ 86,277	$243,329	$ 17,648	$ 24,27
Production (lifting) costs	106,680	32,567	61,018	4,385	8,90
Exploration costs	12,789	5,645	-	-	41
Impairment of proved properties	9,555	18,895	600	-	
Depreciation, depletion and amortization	60,426	52,072	44,252	5,033	2,93
Results of operations before income taxes	170,021	(22,902)	137,459	8,230	12,02
Income tax expense (benefit)	66,138	(8,112)	41,238	2,058	3,00
Results of operations (excluding corporate overhead and interest costs)	$103,883	$(14,790)	$ 96,221	$ 6,172	$ 9,02

	2000				
(In thousands)	U.S.	Canada	Argentina	Bolivia	Ecuado
Revenues	$348,305	$ 2,281	$281,334	$ 19,535	$ 30,61
Production (lifting) costs	96,386	503	52,856	3,777	6,11
Exploration costs	4,271	191	-	12,133	2,52
Impairment of proved properties	225	-	-	-	
Depreciation, depletion and amortization	53,184	586	33,077	7,421	2,06
Results of operations before income taxes	194,239	1,001	195,401	(3,796)	19,90
Income tax expense (benefit)	75,559	447	68,390	(949)	4,97
Results of operations (excluding corporate overhead and interest costs)	$118,680	$ 554	$127,011	$ (2,847)	$ 14,92

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

(In thousands)	1999 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

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, 2001 and 2000, was as follows:

(In thousands)	2001 U.S.	Canada	Argentina	Bolivia	Ecuador
Unproved properties not being amortized	$ 19,188	$ 60,393	$ -	$ -	$ -
Proved properties being amortized	919,399	647,888	652,832	114,429	56,075
Total capitalized costs	938,587	708,281	652,832	114,429	56,075
Less accumulated depreciation, depletion and amortization	506,719	70,271	177,414	20,857	6,351
Net capitalized costs	$ 431,868	$ 638,010	$ 475,418	$ 93,572	$ 49,724

(In thousands)	2000 U.S.	Canada	Argentina	Bolivia	Ecuador
Unproved properties not being amortized	$ 20,446	$ 3,922	$ -	$ -	$ -

Proved properties being amortized	944,582	49,981	533,727	113,399	45,086
Total capitalized costs	965,028	53,903	533,727	113,399	45,086
Less accumulated depreciation, depletion and amortization	493,149	596	132,025	15,873	3,427
Net capitalized costs	$ 471,879	$ 53,307	$ 401,702	$ 97,526	$ 41,659

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 2001, 2000 and 1999:

	2001					
(In thousands)	U.S.	Canada	Argentina	Bolivia	Ecuador	O
Acquisitions:						
Undeveloped properties	$ 1,455	$ 59,033	$ -	$ -	$ -	$
Producing properties	2,506	562,444	42,267	-	-	
Exploratory	20,963	24,839	-	-	411	
Development	36,897	42,992	76,838	1,030	10,988	
Total costs incurred	$ 61,821	$ 689,308	$ 119,105	$ 1,030	$ 11,399	$

	2000					
(In thousands)	U.S.	Canada	Argentina	Bolivia	Ecuador	O
Acquisitions:						
Undeveloped properties	$ 2,176	$ 3,614	$ -	$ 225	$ 265	$
Producing properties	6,035	47,927	43,428	-	(5,942)	
Exploratory	23,841	212	-	27,532	1,494	
Development	32,072	1,035	49,457	983	829	
Total costs incurred	$ 64,124	$ 52,788	$ 92,885	$ 28,740	$ (3,354)	$

	1999				
(In thousands)	U.S.	Argentina	Bolivia	Ecuador	Other

Acquisitions:					
Undeveloped properties..........	$ 510	$ -	$ -	$ -	$
Producing properties...........	31,662	121,015	-	14,110	
Exploratory......................	10,316	-	27,834	-	6,
Development......................	9,083	10,536	2,955	1,981	
Total costs incurred.........	$ 51,571	$ 131,551	$ 30,789	$ 16,091	$ 7,

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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, Ecuador and Trinidad 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 independent petroleum consultants of Outtrim Szabo Associates Ltd.

As discussed in Note 1, the Argentine government took actions which, in effect, caused the devaluation of the peso in early December 2001. Consistent with the assumptions used for the financial statements, as described in Note 1, the Company used the estimated exchange rate of 1.65 pesos to one U.S. dollar to translate peso-denominated future production, development and abandonment costs in estimating proved oil and gas reserves. The resulting reduction in the U.S. dollar cost of these expenses increased the Company's proved reserves in Argentina by approximately 10.9 million BOE at December 31, 2001. As discussed in Note 12, in February 2002, the Argentine government also imposed a 20 percent excise tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. Had this export tax been in effect at December 31, 2001, it would not have materially affected the Company's proved reserve quantities in Argentina.

	Oil (MBbls)				
	U.S.	Canada	Argentina	Bolivia	Ecu
Proved reserves at December 31, 1998............	57,207	-	74,841	8,364	2
Revisions of previous estimates.................	52,684	-	24,496	(1,952)	
Extensions, discoveries and other additions......	110	-	-	1,746	
Production.......................................	(8,643)	-	(7,560)	(77)	
Purchase of reserves-in-place...................	10,343	-	44,694	-	2
Sales of reserves-in-place......................	(1,259)	-	-	-	

Proved reserves at December 31, 1999............	110,442	-	136,471	8,081	4
Revisions of previous estimates.................	397	-	18,501	(1,125)	
Extensions, discoveries and other additions......	329	-	-	-	
Production......................................	(9,044)	(19)	(9,406)	(131)	(
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	6,825	4
Revisions of previous estimates.................	(11,727)	(8,719)	16,899	(589)	
Extensions, discoveries and other additions......	487	2,185	216	-	
Production......................................	(8,409)	(1,539)	(10,548)	(101)	(
Purchase of reserves-in-place...................	-	27,493	11,724	-	
Sales of reserves-in-place......................	(5,739)	-	-	-	
Proved reserves at December 31, 2001............	76,948	21,808	175,827	6,135	5
Proved developed oil reserves at:					
December 31, 1999........................	94,722	-	90,125	6,414	
December 31, 2000........................	90,774	1,558	94,191	5,668	
December 31, 2001........................	66,656	13,259	101,145	4,670	

	Gas (MMcf)				
	U.S.	Canada	Argentina	Bolivia	Trinida
Proved reserves at December 31, 1998.......	385,512	-	12,024	409,297	
Revisions of previous estimates............	32,505	-	25,222	21,129	
Extensions, discoveries and other additions	1,844	-	-	88,424	
Production.................................	(39,150)	-	(4,682)	(4,522)	
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	514,328	
Revisions of previous estimates............	39,123	-	13,990	(41,521)	
Extensions, discoveries and other additions	34,990	-	-	-	
Production.................................	(35,764)	(312)	(8,705)	(8,948)	
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	463,859	
Revisions of previous estimates............	(16,640)	(21,092)	18,768	4,889	
Extensions, discoveries and other additions	5,045	32,157	44	-	64,4
Production.................................	(34,168)	(22,132)	(10,253)	(9,088)	
Purchase of reserves-in-place..............	-	207,701	1,636	-	
Sales of reserves-in-place.................	(27,760)	-	-	-	

Proved reserves at December 31, 2001.......	325,149	236,112	131,394	459,660	64,4
Proved developed gas reserves at:					
December 31, 1999........	302,444	-	92,696	415,743	
December 31, 2000........	333,453	33,405	41,822	385,623	
December 31, 2001........	252,062	206,539	48,689	346,148	25,0

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, Disclosures about Oil and Gas Producing Activities. 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.

The translation of the peso-denominated future production, development and abandonment costs in Argentina discussed above and the resulting reduction in the U.S. dollar cost of these expenses increased the Company's Standardized Measure by approximately $68.2 million at December 31, 2001. Had the Argentina oil export tax discussed above been in effect at December 31, 2001, it would have reduced the Company's Standardized Measure by approximately $98.8 million.

Set forth below is the Standardized Measure relating to proved oil and gas reserves at December 31, 2001 and 2000:

	2001				
(In thousands)	U.S.	Canada	Argentina	Bolivia	Ecuad
Future cash inflows..............	$ 2,131,498	$ 930,656	$ 2,885,530	$ 450,358	$ 528

Future production costs...........	929,408	299,818	1,152,217	47,277	242
Future development and abandonment costs..............	231,237	73,795	340,597	50,950	169
Future net cash inflows before income tax expense.............	970,853	557,043	1,392,716	352,131	116
Future income tax expense.........	271,409	141,784	323,109	80,911	11
Future net cash flows.............	699,444	415,259	1,069,607	271,220	105
10 percent annual discount for estimated timing of cash flows.	296,603	143,552	484,570	147,612	54
Standardized Measure of discounted future net cash flows..........	$ 402,841	$ 271,707	$ 585,037	$ 123,608	$ 50

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	2000			
(In thousands)	U.S.	Canada	Argentina	Bolivia
Future cash inflows....................	$ 6,484,886	$ 355,171	$ 3,757,493	$ 572,
Future production costs................	1,656,100	45,558	1,221,302	48,
Future development and abandonment costs..................	221,193	12,696	281,555	51,
Future net cash inflows before income tax expense.................	4,607,593	296,917	2,254,636	472,
Future income tax expense.............	1,675,283	110,332	665,236	97,
Future net cash flows..................	2,932,310	186,585	1,589,400	374,
10 percent annual discount for estimated timing of cash flows......	1,366,053	39,435	682,169	200,
Standardized Measure of discounted future net cash flows..............	$ 1,566,257	$ 147,150	$ 907,231	$ 174,

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 2001, 2000 and 1999:

(In thousands)	2001	2000	19

Standardized Measure - beginning of year	$ 2,951,121	$ 2,247,237	$ 6
Increases (decreases) -			
Sales, net of production costs	(517,835)	(522,545)	(2
Net change in sales prices, net of production costs	(2,404,154)	1,131,540	1,2
Discoveries and extensions, net of related future development and production costs	83,976	148,727	
Changes in estimated future development costs	(123,254)	(87,127)	(
Development costs incurred	163,122	93,276	
Revisions of previous quantity estimates	(8,646)	267,178	7
Accretion of discount	433,862	298,963	
Net change in income taxes	911,566	(645,108)	(6
Purchase of reserves-in-place	368,552	278,740	4
Sales of reserves-in-place	(141,509)	(4,787)	(
Timing of production of reserves and other	(278,660)	(254,973)	
Standardized Measure - end of year	$ 1,438,141	$ 2,951,121	$ 2,2

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

12. Subsequent Events

On January 6, 2002, the Argentine government enacted an emergency law that required certain contracts that were previously payable in U.S. dollars to be payable in pesos (see Note 1).

On February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The tax is limited by law to a term of no more than five years. The Company currently exports approximately 35 percent of its Argentina oil production. However, management believes that this export tax will have the effect of decreasing all future Argentina oil revenues (not only export revenues) by the tax rate for the duration of the tax. Management believes that the U.S. dollar equivalent value for domestic Argentina oil sales (now paid in pesos) will move over time to parity with the U.S. dollar-denominated export values, net of the export tax, thus impacting domestic Argentina values by a like percentage to the tax. The adverse impact of this tax will be partially offset by the net cost savings resulting from the devaluation of the peso on peso-denominated costs and may be further reduced by the Argentina income tax savings related to deducting such impact. At December 31, 2001, the imposition of the export tax would not have had a material impact on the Company's assessment of impairment of its oil and gas properties in Argentina.

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	Indenture dated as of May 30, 2001, between The Chase Manhattan Bank, as Trustee, and the Company (Filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4, Registration No. 333-63896).
4.6	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).
4.7	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 (Filed as Exhibit 10.15 to the Company's report on Form 10-K for the year ended December 31, 2000, filed March 12, 2001).

10.16	First Amendment to Second Amended and Restated Credit Agreement dated as of August 8, 2001, between the Company, the Lenders party thereto, Bank of Montreal, as administrative agent, Bank of America, N.A., as syndication agent, Societe General, Southwest Agency as documentation agent, and ABN AMRO Bank, N.V., as managing agent (Filed as Exhibit 10 to the Company's report on Form 10-Q for the quarter ended June 30, 2001, filed August 14, 2001).
10.17	Acquisition Agreement dated as of March 27, 2001, between the Company and Genesis Exploration Ltd. (Filed as Exhibit 2 to the Company's report on Form 8-K filed May 15, 2001).
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.
23.4	Consent of Outtrim Szabo Associates Ltd.
99.1	Letter to Commission Pursuant to Temporary Note 3T.

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* Management contract or compensatory plan or arrangement.