VINTAGE PETROLEUM, INC.

Building on Momentum

PROGRESS, PERFORMANCE, POSITIONING, POTENTIAL

2004 Annual Report and Form 10-K

Company Profile

Vintage Petroleum, Inc. is an independent energy company engaged in the acquisition, exploitation and exploration of oil and gas properties and the marketing of natural gas and crude oil. **Vintage's acquisition strategy is to acquire producing properties with significant upside potential at competitive costs. Through exploitation activities, the Vintage staff unlocks the upside potential of acquired properties, increasing production, adding reserves and gaining operational efficiencies. Vintage also explores for oil and gas through a balanced risk program designed to grow reserves and production in the United States over the near term, and through a longer-term, high-impact program that targets locations outside the company's core areas of operations.**

Glossary

BOE: barrels of oil equivalent, using 6 Mcf per barrel ratio
Bcf: billion cubic feet of gas
MBbls: thousand barrels of oil
Mcf: thousand cubic feet of gas
MMBbls: million barrels of oil
MMBOE: million BOE
MMBtu: million British thermal units
MMcfe: million cubic feet of gas equivalent, using 6 Mcf per barrel ratio
NYMEX: New York Mercantile Exchange

About the Cover

Vintage utilizes the latest in three dimensional ("3-D") seismic imaging technology in order to optimize drilling targets. The cover picture is a 3-D seismic map of the company's An Nagyah field in Yemen, an area of successful development in 2004.

VPI at a Glance

Areas of Operation

Vintage's operations are divided into two principal core areas and an international exploration effort. Domestic operations are located in the West Coast, Gulf Coast, East Texas and Mid-Continent areas of the United States and comprise a principal core area. South American operations were initiated in 1995 with Vintage's entry into the San Jorge Basin of Argentina. Subsequent expansion into additional basins in Argentina and entry into Bolivia followed, establishing South America as another core area. Exploration and subsequent development success in Yemen helped establish the area as a modest but rapidly growing operation in 2004.

Vintage revived its acquisition efforts in 2004 by purchasing additional oil and gas producing assets near areas of existing production in the San Jorge Basin of Argentina and in the onshore gulf coast of Alabama.

Reserves

Vintage's estimated proved reserves at year-end 2004 were 437.2 MMBOE composed of 297 MMBbls of oil accounting for 68 percent of total proved reserves and 840 Bcf of gas accounting for the remaining 32 percent of proved reserves. Proved developed reserves at year-end 2004 comprised 67 percent of total proved reserves.

Community Commitment

Vintage is committed to involvement in the communities in which it operates and supports various charitable and educational organizations as well as employee volunteerism. This commitment is made in the belief that the company's success is interdependent with the well-being of these communities.

Value Strategy

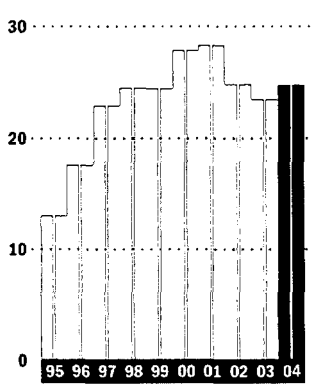
The company's proven strategy of acquire, exploit and explore has achieved profitable growth over time. Its seasoned management and experienced operating team are committed to maintaining financial flexibility and building shareholder returns. Vintage is headquartered in Tulsa, Oklahoma, and its common stock has traded on the New York Stock Exchange under the symbol VPI since its initial public offering in 1990. Additional information is available on the company's web site, *www.vintagepetroleum.com*.

Financial Highlights

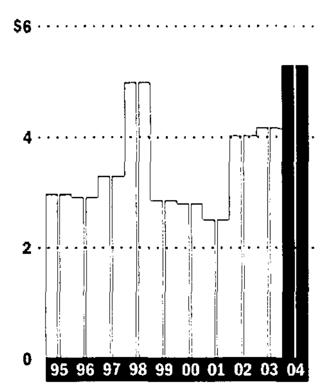
(In thousands except per share amounts or as otherwise indicated)	2004	2003	2002	2001	2000
Financial Highlights					
Revenues	$ 778,180	$ 614,747	$ 518,978	$ 723,535	$ 778,014
Net Income (Loss)	$ 332,592	$ (240,907)	$ (143,664)	$ 133,507	$ 195,893
Net Income (Loss) Per Diluted Share	$ 5.06	$ (3.74)	$ (2.26)	$ 2.09	$ 3.06
Cash Provided by Operating Activities	$ 352,306	$ 233,833	$ 240,869	$ 295,685	$ 395,687
Weighted Average Common					
Shares Outstanding – Diluted	65,784	64,497	63,456	64,027	63,963
Total Assets	$1,644,892	$1,454,259	$1,775,804	$2,107,902	$1,338,397
Long-Term Debt	$ 549,949	$ 699,943	$ 883,180	$1,010,673	$ 464,229
Stockholders' Equity	$ 683,678	$ 422,486	$ 570,992	$ 729,443	$ 624,857
Oil and Gas Capital Expenditures:					
Acquisitions	$ 110,547	$ 463	—	$ 44,773	$ 49,463
Exploitation and Exploration	$ 237,045	$ 148,887	$ 58,905	$ 140,256	$ 156,420
Total	$ 347,592	$ 149,350	$ 58,905	$ 185,029	$ 205,883
Average Realized Oil Price (per barrel)	$ 31.02	$ 25.70	$ 21.28	$ 22.36	$ 25.63
Average Realized Gas Price (per Mcf)	$ 3.99	$ 2.91	$ 2.10	$ 3.63	$ 3.20
Operational Highlights					
Proved Oil Reserves (MBbls)	297,234	292,798	348,697	322,261	318,560
Proved Gas Reserves (MMcf)	840,030	926,038	1,083,546	1,216,724	1,023,208
Total Proved Reserves (MBOE)	437,239	447,138	529,288	535,048	489,095
Annual Sales Volumes (MBOE)	24,525	23,201	24,505	27,977	27,484
Average Daily Oil Production (MBbls)	46	46	49	52	51
Average Daily Gas Production (MMcf)	129	107	109	147	146
Average Daily Oil Equivalent Production (MBOE)	67	64	67	77	75
Three-Year Average Finding Cost (per BOE)	$ 5.27	$ 4.12	$ 4.01	$ 2.49	$ 2.75

All amounts, except proved reserves, reflect the presentation of the company's operations in Canada, Trinidad and Ecuador as discontinued operations for all periods. Production volumes, oil and gas capital expenditures, average realized prices and three-year average finding costs are from continuing operations only.

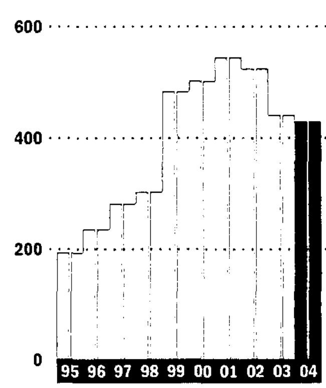
Annual Sales Volume
(MMBOE)



Three-Year Average Finding Cost
($ per BOE)



Proved Reserves
(MMBOE)



To Our Shareholders

Early in 2004 we established three broad goals to revitalize the company. The first goal was to continue to fortify the balance sheet, providing the company with more flexibility to grow through acquisitions.

Charles C. Stephenson, Jr.
Chairman of the Board of Directors,
President and Chief Executive Officer

"I am pleased to report that we have accomplished or made substantial advancement on each objective during 2004 and that the marketplace recognized our progress and potential, raising the share price by nearly 90%."

Secondly, the goals called for a stepped-up effort to rekindle the contribution to growth through acquisitions, a key building block of the company since its inception. Our third objective was to return the company's operational and financial performance, over time, to among the top tier of our industry group. I am pleased to report that we have accomplished or made substantial advancement on each objective during 2004 and that the marketplace recognized our progress and potential, raising the share price by nearly 90 percent. The dramatic increase in the price of Vintage shares during 2004 led to our outperforming many in our peer group and substantially exceeding the rise in all major stock market indices. We have returned the company to profitable growth and are now well positioned to continue the growth in value that our shareholders expect and have profited from in the past. Earnings from continuing operations rose 111 percent to $125 million or $1.91 per diluted share. Likewise, cash flow from continuing operations increased 46 percent to $313 million.

2004 Operational and Financial Performance

The macro-economic environment was very favorable for our business in 2004. Robust world demand for crude oil overtook new supplies and, combined with market concerns for the security of supplies in parts of the Middle East, contributed to a 33 percent increase in the average NYMEX reference price of oil to $41.40 per barrel. Demand for natural gas in the United States rose with an improving economy, similarly contributing to a 12 percent rise in the NYMEX reference price of domestic gas.

Capital Expenditures Aimed at Reinvigorating Growth

We made total capital investments on continuing operations of $348 million during the year, spending $111 million on the acquisition of proved reserves, $180 million for exploitation activities and $57 million for exploration. Non-acquisition capital spending from continuing operations rose to $237 million, up nearly 59 percent from the prior year's $149 million.

As a result of the company's successful drilling campaign in Yemen, construction is underway on an 18 mile pipeline and processing facility that will boost production of crude oil from the company's An Nagyah field. Completion is expected by mid-2005.

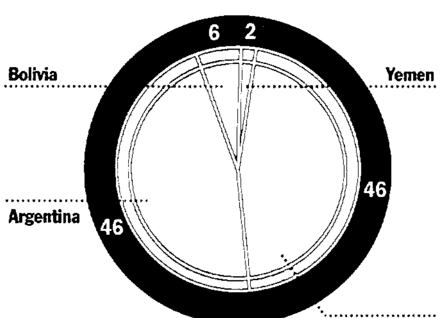
Exploitation activities accounted for approximately 76 percent of total non-acquisition spending. Non-acquisition capital spending was concentrated on lower-risk exploitation activities in an effort to reinvigorate internally generated production, reversing the negative impact which resulted from our decisions to restrict spending in 2002 and 2003 in favor of debt reduction and prudence during Argentina's period of economic and political turmoil. The largest portion of the increase was aimed at revitalizing production in Argentina. Capital spending in Yemen was also substantially raised as continued drilling success rapidly increased production capacity. Similarly, exploitation capital spending in the United States rose 25 percent compared with the prior year reflecting ongoing development successes and an increase in economically attractive projects.

Capital spending for exploration accounted for the remaining 24 percent of non-acquisition expenditures. Capital spent for exploration in the United States was divided between conventional Gulf Coast plays targeting natural gas and the generation of several plays in our new unconventional gas resource effort. Yemen was also a focus of exploration spending, with the objective to test several new oil prospects.

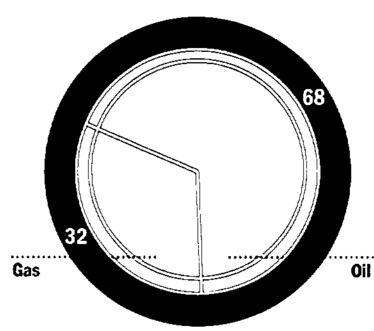
Production from Continuing Operations Grew at 6 Percent

Production from continuing operations responded to the increased spending and rose 6 percent to 24.5 million BOE as a result of contributions from all our producing areas: the United States, South America and Yemen. Daily production of 3,800 BOE, resulting from acquisitions made during the year, contributed modestly to total production due to the timing of the closings in the third and fourth quarters. However, their benefit to production in 2005 will be meaningful.

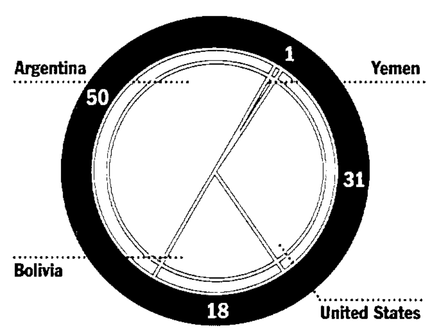
Production
(% by Country)



Proved Reserves
(% by Product)



Proved Reserves
(% by Country)



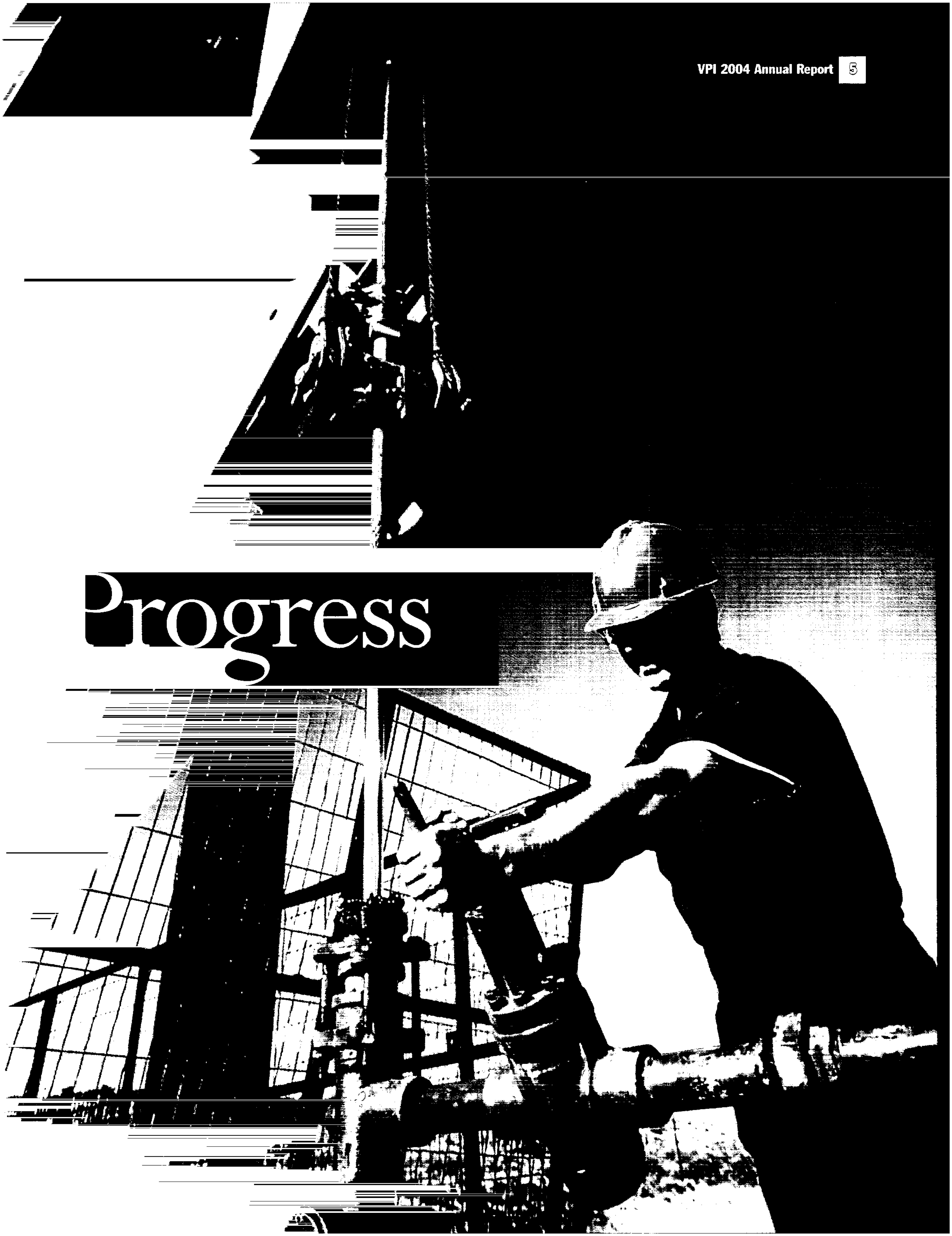
Argentina production responded to the increased capital spending, rising each successive quarter. Spurred by a 60 percent increase in the capital budget, the level of drilling rose substantially to 81 wells, a 19 percent increase over the 2003 level. Daily net oil production exceeded 31,000 barrels in late 2004, an all-time high and substantially above the low point in late 2002 which followed the disruption resulting from political and economic turmoil. Our drilling success was again high, allowing us to maintain our cumulative success rate of 97 percent from drilling over 450 wells since entering the country in 1995. In addition, we continued to lay the groundwork for future production growth by expanding waterflood activity and acquiring additional 3-D seismic surveys. The application of 3-D seismic to our well-selection process has been a principal contributor to a comparatively low three-year finding cost of reserves of $3.75 per BOE and a cumulative finding cost of $2.87 per BOE since entering the country in 1995.

"During 2004, Vintage initiated an exploration program focused on the longer-term development and production of natural gas from unconventional resources in the United States such as gas produced from shale ..."

Similarly in the United States, our most mature production area, volumes responded to increased spending and our focus on drilling to convert proved undeveloped reserves to production. Production grew nearly 12 percent, principally as a result of successful exploitation in several South Central Texas fields and in the Main Pass 116 complex in the Gulf of Mexico, supplemented by the addition of volumes from exploration. In the Luling, Darst Creek and West Ranch fields in Texas, continued vigorous exploitation activity resulted in the doubling of the daily production rate over the last two years. Similarly, drilling and workover activity at our Main Pass 116 complex has raised net daily production to 13.1 MMcfe from 1.1 MMcfe earlier in the year.

The company's conventional exploration program made multiple discoveries in the offshore Gulf of Mexico during 2004. Production commenced in July from the 2003 discoveries at the High Island 55-L block and grew as an additional well was drilled on the block and at the adjoining High Island 56-L block. Apparent discoveries were also made at Matagorda Island blocks 639 and 640.

During 2004, Vintage initiated an exploration program focused on the longer-term development and production of natural gas from unconventional resources in the United States, such as gas produced from shale and coal and basin-centered gas produced from unusually tight sands. Unlike conventional exploration plays, the presence of hydrocarbons is not the highest element of risk. Rather, often the existence of hydrocarbons is known from wells drilled in prior years, but the design of a cost-effective method of economic development and extraction represents the greatest risk. Advances in fracture stimulation techniques, coupled with the prospect of a continued elevated price for domestic natural gas, have combined to make these resources economically viable to produce. However, much remains to be understood industry-wide regarding the factors which control the economic development of unconventional gas resources. The potential reward of pursuing an unconventional gas resource program is that if a play concept can be commercially produced, it has the capacity to be repeated multiple times over a large area with relatively low risk, somewhat akin to mining. Throughout the year, we evaluated numerous unproven, unconventional resource plays and selected a minimum of four plays to test during 2005.



Progress

In late 2003, the government of the Republic of Yemen approved the company's development plan and designated as commercial a 285,000-acre area inclusive of our An Nagyah, An Naeem and Harmel discovery wells. We drilled eight consecutive successful appraisal wells during the year, dramatically increasing the productive capacity of the An Nagyah field. Design and installation of permanent central processing and pipeline facilities necessary to export oil production is under way. Diligent effort by our employees in conjunction with the full support and cooperation of the Yemeni government allowed us to initiate production during the second quarter 2004 at a modest rate of 1,300 net BOPD and, with drilling success, to increase the rate to 3,800 BOPD at year-end. In the short period since commencement, total gross production from An Nagyah has reached 1 million barrels. Production is temporarily trucked to a nearby existing pipeline and sent to an export facility.

After a hiatus of more than two years, we rekindled acquisitions as an integral part of our growth strategy. We successfully consummated two transactions of producing properties during the second half of the year in close proximity to existing Vintage operations. We purchased a property with potential for further exploitation in the northern flank of the San Jorge Basin in Argentina, and in late 2004, a rig was mobilized to initiate planned exploitation activities. We also acquired a producing property in south Alabama in a negotiated transaction with ExxonMobil.

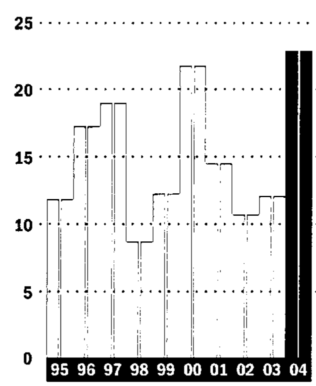
Fortified Balance Sheet with Proceeds from Sale of Canadian Interest

The company took strategic advantage of the exceptionally strong demand for producing oil and gas properties in Canada, created by the acquisitive energy income trust sector, and sold its Canadian interests during 2004. Excess cash flow from continuing operations, coupled with proceeds of $275 million from the sale of our Canadian interest, combined to further improve our financial position. Proceeds were applied to eliminate borrowings under the company's bank revolving credit facility, to fund the two principal acquisitions during the year and for general corporate purposes. Net debt at year-end was reduced to $426 million compared to $650 million at year-end 2003.

Performance

"The dramatic increase in the price of Vintage shares during 2004 led to our outperforming many in our peer group and substantially exceeding the rise in all major stock market indices."

Year-end Stock Price
($)



Similarly, our net debt-to-book capitalization ratio at year-end 2004 dropped substantially, ending at 38 percent compared to 60 percent at last year-end. We have borrowing capacity nearly equal to our bank credit facility of $300 million and cash of $124 million which will allow significant flexibility to fund additional growth in the future.

Reserve Additions Replace 119 Percent of Production from Continuing Operations

Vintage's estimated proved reserves from continuing operations grew to 437 MMBOE, the product of net reserve additions in each of our principal producing areas and higher oil and gas prices. Year-end 2004 proved reserves are comprised of 297 MMBbls of oil and 840 Bcf of natural gas, representing 68 percent and 32 percent of total proved reserves, respectively. Of the total, 67 percent were classified as proved developed reserves. Excluding results from activity on divested Canadian properties, net additions and revisions to reserves totaled 29.2 MMBOE, replacing 119 percent of total company production at a finding cost of $11.90 per BOE. In contrast to our three-year average finding cost of $5.27 per BOE, excluding discontinued operations, our 2004 finding cost was above our historical average due to several factors. The primary focus for the year was to increase production. Consequently, we chose to spend 55 percent of our non-acquisition capital budget primarily targeting exploitation projects which converted proved undeveloped reserves to proved developed producing status, as well as for processing facilities in Yemen, waterflood projects in Argentina and certain exploration projects which are expected to contribute to production beyond 2004. In addition, the price of oilfield services rose in step with rising commodity prices. Further, we realized a smaller contribution to reserve additions from conventional exploration spending than in the past.

Vintage's capital spending program is aimed at revitalizing growth – production from continuing operations grew 6% in 2004 with contributions from all producing areas: the United States, South America and Yemen.

Based on 2004 year-end NYMEX prices of $43.45 per barrel for oil and $6.15 per MMBtu for gas plus year-end price differentials, the present value of estimated future net revenues, before income taxes, discounted at 10 percent (PV10), attributable to total proved reserves was approximately $3.7 billion at year-end 2004. This compares to a PV10 of $3.3 billion at year-end 2003, excluding Canada. The standardized measure of discounted future net cash flows, which deducts discounted future income taxes from PV10, was $2.5 billion and $2.2 billion at year-end 2004 and 2003 (excluding Canada), respectively.

2005 Goals and Operational Outlook

Goals for 2005

Our goals for 2005 target profitable growth from a balanced platform of acquisitions, exploitation and exploration:

- Seek acquisition opportunities as a source of growth and finance with an appropriate amount of cash flow, equity and debt in order to maintain a balance sheet capable of supporting continued growth;
- Execute ongoing exploitation plans in core areas of the United States, Argentina and Yemen to mitigate production declines and support internal growth;
- Increase inventory of both conventional and unconventional gas projects in our U.S. exploration program to support replacement of production and future growth;
- Continue to invest a small amount of funds in other potential high-impact frontier exploration opportunities, particularly Yemen, which can have a significant future impact on company value.

Acquisition Activity

Acquisitions have been a key contributor to our long-term growth, and we continue to target producing properties with significant upside potential as a means of fostering profitable reserve and production growth. Today, there is an ample supply of properties on the market, however, the environment remains very competitive. Any significant acquisitions we make would be accompanied by appropriate levels of hedging to mitigate price risk and an appropriate mix of cash flow, debt and equity capital in order to maintain our current balance sheet strength. Building on the successful reinvigoration of our acquisition program in 2004, we are committed to pursuing acquisition opportunities in the United States and international venues that complement our areas of focus and core competencies.

"We have returned the company to profitable growth and are now well positioned to continue the growth in value that our shareholders expect and have profited from in the past."

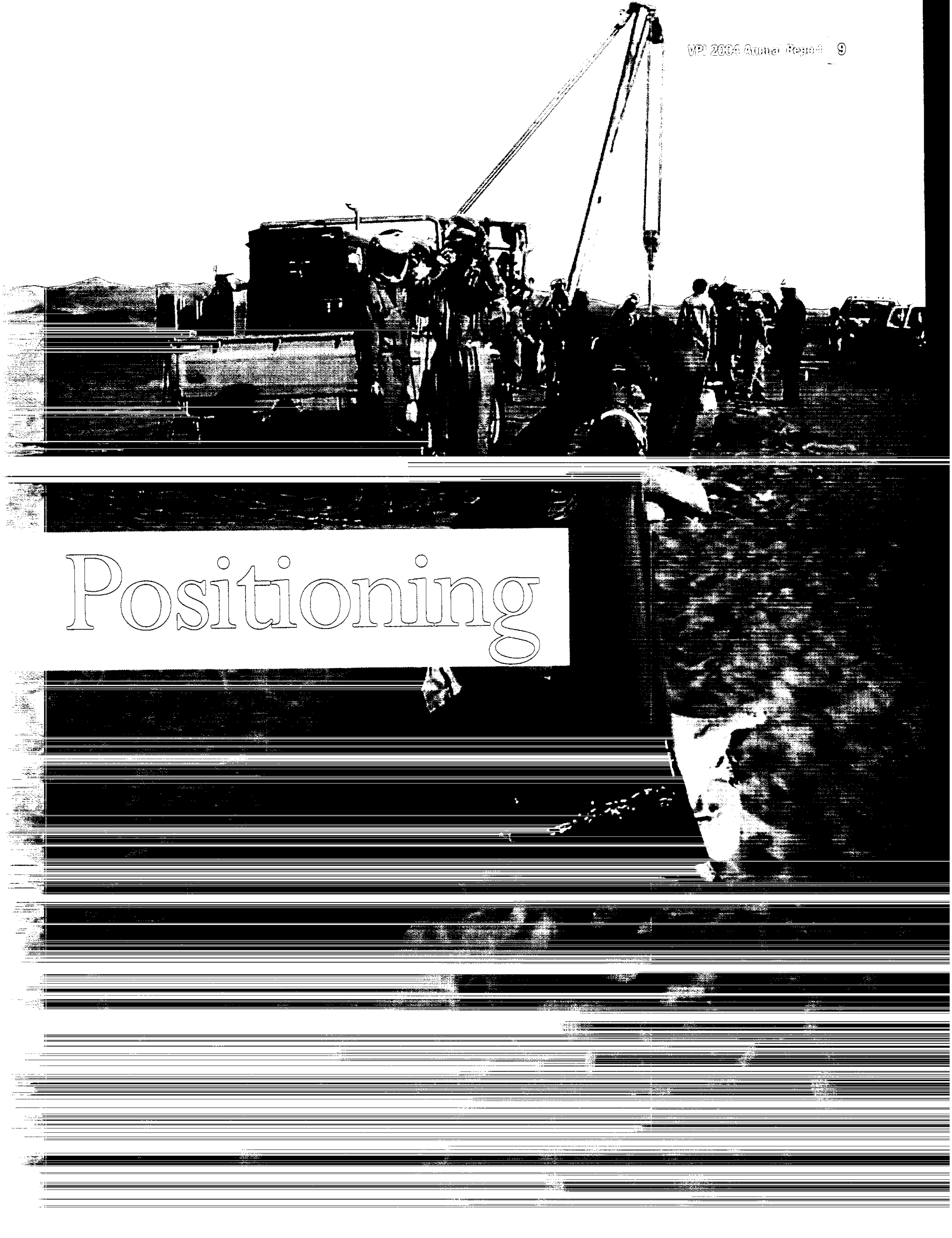
2005 Capital Spending Budget

Vintage's non-acquisition capital budget totals $250 million for 2005, 5 percent above the $237 million spent in 2004, excluding Canada. Approximately 71 percent of the total budget, or $178 million, is allocated to lower-risk exploitation activities in the United States, Argentina and Yemen, while the remaining 29 percent, or $72 million, is devoted to exploration principally in the United States.

United States

Approximately 42 percent, or $104 million, of the total capital budget is targeted for the United States, with $40 million allocated to the drilling of approximately 20 development wells and 45 workovers principally in South Central Texas, Louisiana and California. We plan to spend $64 million to test several potentially significant unconventional gas resource plays and to continue conventional exploration targeting gas prospects with near-term development potential concentrated along the onshore and offshore Texas Gulf Coast.

A total of $26 million in capital has been allocated to test at least three "Barnett shale" type gas plays and one basin-centered tight gas sand play during 2005 in order to provide exposure to significant long-term reserve and production growth. We have accumulated in excess of 128,000 leased and optioned acres in the Palo Duro Basin of West Texas and have drilled the first of two wells to test a shale gas play. Approximately 10 wells are anticipated to be drilled during 2005 to test identified plays and additional acreage is being leased in preparation for this purpose. Additionally, we continue to evaluate other unconventional gas resource opportunities and expect to add several other plays if technical work validates these concepts. If we are


Positioning

successful at commercializing the identified plays, they could provide significant future growth in reserves and production in 2006 and beyond.

In the conventional exploratory program, we are pursuing company-generated Oligocene and Miocene prospects based on 3-D seismic and geochemical surveys. Capital of $38 million has been budgeted for conventional exploration, including the drilling of 11 wells during the year. As part of the program, we are currently acquiring 3-D seismic in the Nueces Bay of Texas to support a multi-well drilling program anticipated to commence in the second half of the year. Facility and pipeline construction is also under way to bring on production from apparent discoveries at Matagorda Island blocks 639 and 640, with production anticipated to commence in mid-2005 upon completion and installation of a production platform facility.

Potential

"Acquisitions have been a key contributor to our long-term growth, and we continue to target producing properties with significant upside potential as a means of fostering profitable reserve and production growth."

Argentina

Encouraged by the country's recent return to political stability and economic improvement, we are continuing to increase spending levels in order to accelerate production growth. We increased Argentina's non-acquisition capital budget by over 62 percent to $93 million in 2004 and were successful in revitalizing production. This year, we have increased the budget by another 21 percent to $113 million to support continued production growth. Planned capital spending accounts for 45 percent of the total company capital budget and is allocated to lower-risk exploitation projects.

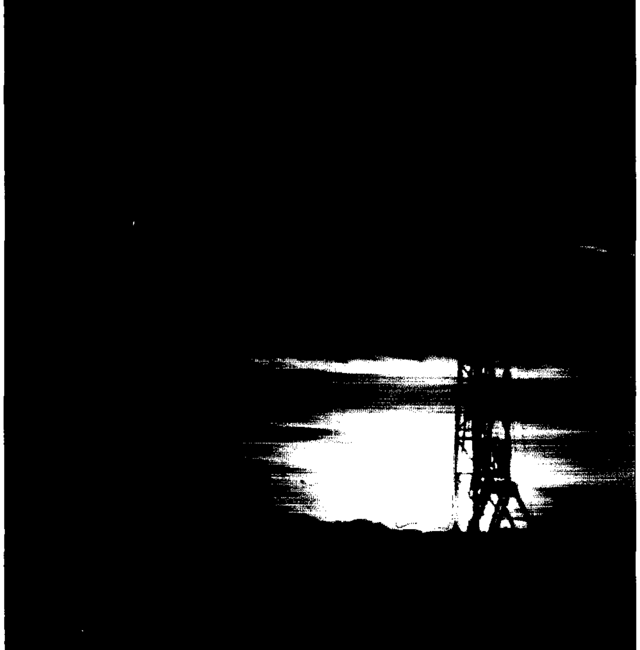
Accordingly, we plan to run five drilling rigs and target the drilling of 110 wells, compared to 2004's four rig program which culminated in the drilling of 81 wells. Further, we are stepping up our secondary recovery activity to take advantage of the favorable reservoir response to waterflood applications. The opportunity for us to significantly increase oil production from waterfloods above the current level of 20 percent of our Argentina oil production to the 40-50 percent of oil production enjoyed by neighboring operators represents a long-term adjunct to growth that we have begun to capitalize upon with increased allocation of capital. We anticipate that increased drilling and waterflood activity could raise total Argentina production by nearly 20 percent in 2005 and contribute to significantly offsetting the company's natural production decline.

Our drilling success rate of 97 percent and multi-year inventory of drilling and waterflood projects provide visibility to our future growth. Drilling success has consistently generated additional proved undeveloped, probable and possible locations for future drilling. At year-end 2004, we had well in excess of 400 proved undeveloped locations and additionally had identified more than 400 probable and possible locations to be drilled.

International Exploration

We plan to spend $31 million, or 12 percent of the total capital budget, primarily in Yemen for facilities design and construction, additional development drilling and exploration. Approximately $18 million has been earmarked for the construction of production facilities and a pipeline near the An Nagyah light-oil discovery. Facilities are being installed to process 10,000 gross BOPD. The company currently realizes 52 percent of gross production or approximately 4,000 net BOPD. Once the facilities are completed and installed, based on current production capacity, the company expects initial production to meet or exceed the previously targeted start-up rate of 10,000 gross BOPD. The remaining portion of our 2005 budget in Yemen is allocated to the drilling of several additional development wells at An Nagyah, testing and evaluating the economic feasibility of further development of the reservoir at our Harmel discovery and one additional exploration well.

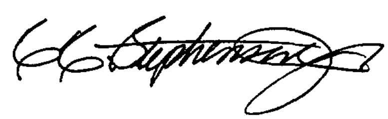
Continuing Progress in Argentina



Exploitation and acquisition activities over the past ten years in Argentina have resulted in the replacement of nearly 280% of production. Enhanced by the use of 3-D seismic imaging, finding costs have averaged a low $2.87 per BOE on the more than 450 wells drilled since operations commenced in 1995.

In Conclusion

Vintage became a public company in 1990. Throughout the 1990s, the company was a leader within its peer group for shareholder return and performance. The management change made in early 2004 is a commitment by the Board of Directors to return the company to being a top performer. Execution of this and our other stated goals in 2004 expanded our sources of growth and substantially improved our financial strength and flexibility, positioning us to continue to enhance shareholder returns. We acknowledge the continued dedication and perseverance of our employees in the achievement of our 2004 goals, and we thank our shareholders for their continued and patient support.



Charles C. Stephenson, Jr.
Chairman of the Board of Directors,
President and Chief Executive Officer

March 14, 2005

Directors:

William L. Abernathy
Executive Vice President and Chief Operating Officer
Vintage Petroleum, Inc.

Rex D. Adams (2,3)
Professor and Former Dean of the
Fuqua School of Business, Duke University

William C. Barnes
Executive Vice President and Chief Financial Officer,
Secretary and Treasurer, Vintage Petroleum, Inc.

Bryan H. Lawrence (1,3)
Senior Manager, Yorktown Partners LLC

Joseph D. Mahaffey (1,2)
Former Managing Director
The Fremont Group

Gerald J. Maier (1,3)
Former Chairman
TransCanada PipeLines

John T. McNabb, II (1,2,3)
Chief Executive Officer
Growth Capital Partners, Inc.

Charles C. Stephenson, Jr.
Chairman of the Board of Directors,
President and Chief Executive Officer
Vintage Petroleum, Inc.

Committees:
Audit (1), Compensation (2), Nominating (3)

Officers:

Charles C. Stephenson, Jr.
Chairman of the Board of Directors,
President and Chief Executive Officer

William L. Abernathy
Executive Vice President and Chief Operating Officer

William C. Barnes
Executive Vice President and Chief Financial Officer,
Secretary and Treasurer

Larry W. Sheppard
Senior Vice President – New Ventures

Kellam Colquitt
Vice President – Exploration

Robert W. Cox
Vice President – General Counsel

Murphy B. Herrington
Vice President – Acquisitions

J. Chris Jacobsen
Vice President – U.S. Operations

Andy R. Lowe
Vice President – Marketing

Michael F. Meimerstorf
Vice President and Controller

Robert E. Phaneuf
Vice President – Corporate Development

Gary A. Watson
Vice President – International

GAAP to Non-GAAP Reconciliation Table

Cash flow from continuing operations, a non-GAAP measure, represents cash provided by operating activities before the impact of discontinued operations, changes in working capital items related to operating activities, all exploration costs, current taxes on property sales and further adjusted for payments on derivative transactions no longer qualifying for hedge accounting which are reflected as investing activities under GAAP. This non-GAAP measure is presented because management believes it is a useful adjunct to cash provided by operating activities under accounting principles generally accepted in the United States (GAAP). This non-GAAP cash flow measure is widely accepted as a financial indicator of an oil and gas company's ability to generate cash which is used to internally fund exploration and development activities and to service debt and is comparable to targets established by the company. This non-GAAP measure is not a measure of financial performance under GAAP and should not be considered as an alternative to cash provided (used) by operating, investing, or financing activities as an indicator of cash flows, or as a measure of liquidity.

Year ended December 31,	2004	2003
Cash provided by operating activities (GAAP measure)	$352,306	$233,833
Adjustments to remove the impact of:		
Cash provided by discontinued operations	(14,705)	(21,295)
Changes in working capital items related to operating activities	(24,292)	(15,887)
Exploration geological and geophysical costs	10,766	9,978
Current tax provision associated with miscellaneous property sales	–	9,978
Payments on derivative transactions included in investing activities	(10,917)	–
Cash flow from continuing operations (non-GAAP measure)	$313,158	$215,230

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2004

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	**73-1182669**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
110 West Seventh Street **Tulsa, Oklahoma**	**74119-1029**
(Address of principal executive offices)	(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, $0.005 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. ☒

Indicate by check mark whether the Registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes X No__

As of June 30, 2004, the aggregate market value of the Registrant's Common Stock held by non-affiliates was approximately $912,505,000.

As of February 28, 2005, 66,072,702 shares of the Registrant's Common Stock were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's Proxy Statement for the Annual Meeting of Stockholders to be held May 10, 2005, are incorporated by reference into Part III of this Form 10-K.

VINTAGE PETROLEUM, INC.
FORM 10-K
YEAR ENDED DECEMBER 31, 2004
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Certain Definitions

As used in this Form 10-K:

Unless the context requires otherwise, all references to "Vintage," "Company," "we," "our," "ours," and "us" refer to Vintage Petroleum, Inc., its consolidated subsidiaries and its proportionately consolidated general partner and limited partner interests in various joint ventures.

"Oil" means crude oil, condensate and natural gas liquids. "Condensate" means hydrocarbons which are in a gaseous state under reservoir conditions but which become liquid at the surface and may be recovered by conventional separators. "Natural gas liquids" means hydrocarbons found in natural gas which may be extracted as liquified petroleum gas and natural gasoline. "Gas" means natural gas.

"Mcf" means thousand cubic feet, "MMcf" means million cubic feet, and "Bcf" means billion cubic feet. "Btu" means British thermal units, the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit, and "MMBtu" means million British thermal units. "Bbl" means barrel, or 42 U.S. gallons liquid volume, "MBbls" means thousand barrels and "MMBbls" means million barrels. "BOE" means equivalent barrels of oil, "MBOE" means thousand equivalent barrels of oil and "MMBOE" means million equivalent barrels of oil. Unless otherwise indicated in this Form 10-K, gas volumes are stated at the legal pressure base of the state or area in which the reserves are located and at 60° Fahrenheit. BOE are determined using the ratio of six Mcf of gas to one Bbl of oil.

"Working interest" means the operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith. "Royalty interest" means an interest in an oil and gas property entitling the owner to a share of oil and gas production free of cost of production.

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

"Development well" means a well drilled within the proved area of an oil or gas reservoir, as indicated by reasonable interpretation of available data, to the depth of a stratigraphic horizon known to be productive. "Exploratory well" means a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend the proved limits of a known reservoir. "Dry hole" means a well found to be incapable of producing either oil or gas in sufficient quantities to justify completion of the well. "Productive well" means a well that is producing oil or gas or that is capable of production including gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

"Infill drilling" means drilling of an additional well or wells provided for by an existing spacing order to more adequately drain a reservoir. "Recompletion" means the completion for production of an existing wellbore in a different formation or producing horizon, either deeper or shallower, from that in which the well was previously completed. "Workover" means remedial operations on a well with the intention of restoring or increasing production from the same zone, including plugging back, squeeze cementing, reperforating, cleanout and acidizing.

"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.

"Developed acreage" means the number of acres which are allocated or assignable to producing wells or wells capable of production. "Undeveloped acreage" means the number of acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas regardless of whether such acreage contains proved oil and gas reserves.

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 we expect, believe or anticipate 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;
- expansion and growth of our business and operations; and
- events or developments in foreign countries, including estimates of oil export levels.

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

- risk factors discussed in this Form 10-K and listed from time to time in our filings with the Securities and Exchange Commission;
- oil and gas prices;
- exploitation and exploration successes;
- actions taken and to be taken by the foreign governments as a result of economic conditions;
- 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 us;
- changes in laws or regulations; and
- other factors, most of which are beyond our control.

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 us will be realized or, even if substantially realized, that they will have the expected consequences to or effects on us or our business or operations. We assume 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.

Website Access to Reports

Our public internet site is http://www.vintagepetroleum.com. We make available free of charge through our internet site, via a link to the EDGAR database of the Securities and Exchange Commission ("SEC"), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

In addition, we make available on http://www.vintagepetroleum.com our annual report to stockholders. You will need the Adobe Acrobat Reader software installed on your computer to view this document, which is in PDF format. If you do not have Adobe Acrobat Reader installed, a link to Adobe Systems Incorporated's internet site, where you can download the software, is provided.

General

We are an independent energy company with operations primarily in the exploration and production and gas marketing segments of the oil and gas industry. We are focused on the acquisition of oil and gas properties which contain the potential for increased value through exploitation and exploration. Through our experienced management and technical staff, we have 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. In addition to our exploration and development activities associated with acquisitions, we continue to build an inventory of exploration prospects in the United States that may impact production in the near term as well as high potential frontier prospects that may impact production in the longer term.

At December 31, 2004, we owned and operated producing properties in nine states in the U.S., with our proved reserves in the U.S. located primarily in four core areas: West Coast, Gulf Coast, East Texas and Mid-Continent. Additionally, we have international core areas located in Argentina, Yemen and Bolivia. In Argentina, we have 22 concessions, 19 of which we operate. Fourteen of these operated concessions are located in the south flank of the San Jorge Basin in southern Argentina. We also have four concessions (two are operated) in the Cuyo Basin in western Argentina acquired through various acquisitions in 2000 and 2001. In September 2004, we made our initial entry into the northern flank of the San Jorge Basin in Argentina with our purchase of Petrolera Rio Alto S.A. whose principal asset is the producing Bella Vista Oeste concession. This acquisition gave us 100 percent working interest in the Bella Vista Oeste concession which we operate. (See "Acquisitions.") In Bolivia, we own and operate three concessions in the Chaco Plains area of southern Bolivia and the Naranjillos concession located in the Santa Cruz Province. We operate the S-1 Damis block in Yemen, where initial production began during the second quarter of 2004. We also continue to pursue exploration opportunities in Yemen and we have ongoing exploration activities in Bulgaria. In 2003, we sold our operations in Ecuador, where we operated three block in the Oriente Basin, and in 2004 we sold our Canadian operations. (See "Divestitures.")

As of December 31, 2004, we owned interests in 2,810 gross (2,436 net) productive wells in the U.S., of which approximately 92 percent are operated by us, 1,623 gross (1,470 net) productive wells in Argentina, of which approximately 85 percent are operated by us, 15 gross (14 net) productive wells in Bolivia, all of which are operated by us and 10 gross (8 net) productive wells in Yemen, all of which are operated by us. As of December 31, 2004, our properties had proved reserves of 437.2 MMBOE, comprised of 297.2 MMBbls of oil and 840 Bcf of gas, with a present value of estimated future net revenues before income taxes (utilizing a 10 percent discount rate) of $3.7 billion and a standardized measure of discounted future net cash flows of $2.5 billion. Our net daily production from continuing operations for the fourth quarter of 2004 averaged 47.5 MBbls of oil and 143.7 MMcf of gas.

Financial information relating to our industry segments is set forth in Note 9 "Segment Information" to our consolidated financial statements included elsewhere in this Form 10-K.

We were incorporated in Delaware on May 31, 1983. Our principal office is located at 110 West Seventh Street, Tulsa, Oklahoma 74119-1029, and our telephone number is (918) 592-0101.

Business Strategy

Our overall goal is to maximize value through profitable growth in oil and gas reserves and production. We have been successful at achieving this goal through an 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 and undeveloped properties, (c) maintaining efficient operations and (d) maintaining financial flexibility. Key elements of our strategy include:

- *Acquisitions of Producing Properties.* We have an experienced management and technical team which focuses on acquisitions of operated producing properties that meet our selection criteria. These criteria 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. Our emphasis on property acquisitions reflects our 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 us to rapidly grow our reserves at favorable acquisition prices. From January 1, 2000, through December 31, 2004, we spent $809.7 million acquiring 112.3 MMBOE of proved oil and gas reserves at an average acquisition cost of $7.21 per BOE. We replaced, through acquisitions, approximately 74 percent of our production of 151.4 MMBOE during the same period. For additional information, see "Acquisitions." We are continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than many of those we have consummated to date. No assurance can be given that any such acquisitions will be successfully consummated.

- *Exploration and Development.* We pursue workovers, recompletions, secondary recovery operations and other production optimization techniques on our properties, as well as development and infill drilling, with the goals of offsetting normal production declines and replacing our annual production. Our overall exploration strategy balances high potential international prospects with lower risk drilling in known formations in the United States and Argentina. We make extensive use of geophysical studies, including 3-D seismic data, which reduces the cost of our exploration and development programs by increasing our success rate. From January 1, 2000, through December 31, 2004, we spent approximately $962.6 million on exploration and development activities. As a result of all of these activities, including the impact of reserve revisions, during the five-year period ended December 31, 2004, we succeeded in adding 100.9 MMBOE to proved reserves, replacing approximately 67 percent of production during the same period at a cost of $9.54 per BOE. During 2004, we spent $254.7 million on exploration and development activities and added 15.0 MMBOE to proved reserves (including Canadian additions and revisions), replacing approximately 54 percent of 2004 production at a cost of $16.96 per BOE. For additional information, see "Exploration and Development." We continue to maintain an extensive inventory of exploration and development opportunities. The total 2005 non-acquisition capital budget has been set at $250 million. The exploration portion of the 2005 capital budget of approximately $72 million will focus primarily on the United States, with other projects planned for Yemen and Bulgaria.

- *Efficient Operations.* We believe we are an efficient operator and capitalize on our lower cost structure in evaluating acquisition opportunities. We have generally achieved substantial reductions in labor and other field level costs from those experienced by the previous operators. In addition, we target acquisition candidates that are located in our core areas and provide opportunities for cost efficiencies through consolidation with our other operations. The lower cost structure has generally allowed us to substantially improve the cash flows of newly acquired properties.

- *Financial Flexibility.* We are committed to maintaining financial flexibility, which we believe is important for the successful execution of our acquisition, exploitation and exploration strategy. Since 1990, we have completed five public equity offerings, two public debt offerings and three Rule 144A private debt offerings, all of which have provided us with aggregate net proceeds of approximately $1.2 billion. Our debt, less cash on hand, at December 31, 2004, was $425.7 million. Cash on hand, internally generated cash flows, the borrowing capacity under our revolving credit facility and our ability to adjust our level of capital expenditures are our major sources of liquidity. In addition, we may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions we might secure in the future and maintain our financial flexibility. For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Capital Resources and Liquidity" included elsewhere in this Form 10-K.

Acquisitions

Historically, we have allocated a substantial portion of our capital expenditures to the acquisition of producing oil and gas properties. Our continuing emphasis on reserve additions through property acquisitions reflects our belief that consolidation and restructuring activities on the part of major integrated, large independent and national oil companies have afforded in recent years, and should afford in the future, favorable opportunities to purchase domestic and international producing properties.

Since our incorporation in May 1983, we have been actively engaged in the acquisition of producing oil and gas properties, primarily in the West Coast, Gulf Coast, East Texas and Mid-Continent areas of the U.S. In 1995, we made a series of acquisitions that established a core area in the San Jorge Basin in southern Argentina. In late 1996, we expanded our South American operations into Bolivia and, in 1998, into Ecuador. In 1998, we entered into a farm-in agreement for the S-1 Damis exploration block in Yemen and in December 2000, we made our initial entrance into Canada and Trinidad with the purchase of 100 percent of Cometra Energy (Canada), Ltd. ("Cometra"), a privately-held Canadian company. We significantly expanded our Canadian operations in 2001 with the purchase of 100 percent of Genesis Exploration, Ltd. ("Genesis"), a publicly-traded Canadian company. We also extended our Argentine operations in 2000 with our acquisition of two concessions from Perez Companc, in 2001 with our purchase of the La Ventana and Rio Tunuyan concessions from Shell C.A.P.S.A., a wholly-owned affiliate of Royal Dutch Shell and most recently in September 2004 with our purchase of Petrolera Rio Alto S.A. ("PRASA"), a subsidiary of Rio Alto Resources International, Inc. In December 2004, we expanded our ownership in Alabama with the $77.2 million acquisition of Exxon Mobil Corporation's interest in the Big Escambia Creek field and gas processing facility adjacent to our Flomaton and Fanny Church fields and plant. This acquisition is consistent with our historical philosophy of improving cash flow by reducing operating costs on newly acquired properties through economies of scale due to existing operations in the area. We are constantly identifying and evaluating additional acquisition opportunities which may lead to our expansion into new domestic core areas or other countries which we believe are politically and economically stable.

From January 1, 2000, through December 31, 2004, we made oil and gas reserve acquisitions with costs totaling approximately $809.7 million. As a result of these acquisitions, we acquired approximately 112.3 MMBOE of proved oil and gas reserves. The following table summarizes our acquisition experience during the periods indicated:

	Acquisition Costs (In thousands)	Proved Reserves When Acquired: Oil (MBbls)	Gas (MMcf)	MBOE	Cost Per BOE When Acquired
North America Acquisitions:					
2000	$ 53,962	2,854	41,166	9,715	$ 5.55
2001	564,950	27,493	207,701	62,110	9.10
2002	-	-	-	-	-
2003	463	90	258	133	3.48
2004	75,599	5,690	17,381	8,587	8.80
Total North America Acquisitions	694,974	36,127	266,506	80,545	8.63
South America Acquisitions:					
2000	37,486	11,970	2,278	12,350	3.04
2001	42,267	11,724	1,636	11,997	3.52
2002	-	-	-	-	-
2003	-	-	-	-	-
2004	34,948	7,411	-	7,411	4.72
Total South America Acquisitions	114,701	31,105	3,914	31,758	3.61
Total Acquisitions	$ 809,675	67,232	270,420	112,303	7.21

The following is a brief discussion of the significant acquisitions in 2004:

Gulf Coast Area of Alabama. In December 2004, we acquired 100 percent of Exxon Mobil Corporation's interest in the Big Escambia Creek field and processing facility for $77.2 million cash. Approximately $73.9 million of the purchase price was allocated to oil and gas reserves.

The field produces condensate, gas and liquids from the Smackover formation and current net production is approximately 1,920 BOE per day. The field consists of 13 operated and two non-operated wells, and is adjacent to our existing operated Flomaton and Fanny Church fields and plant. We believe that this expansion of our existing operating area will enable us to increase production and profitability through a series of planned facility modifications, drilling and increased operational efficiencies.

The acquired property and facilities are a logical extension to our existing property base, have producing characteristics similar to our adjacent fields and have well established, predictable production decline rates. These properties provide us with the type of operational and work program opportunities in which we have been successful in the past. Funds for this acquisition were provided primarily from cash on hand resulting from the sale of our interests in Canada. (See "Divestitures.")

Northern Flank of San Jorge Basin (Argentina). In September 2004, we acquired 100 percent of PRASA, the wholly-owned Argentine subsidiary of Rio Alto Resources International, Inc. for total consideration of $34.9 million in cash. The acquired company's principal asset is the operated Bella Vista Oeste producing concession which covers approximately 54,000 acres in the northern flank of the San Jorge Basin of Argentina.

Net production attributable to the producing Bella Vista Oeste concession at the time of our acquisition was estimated at 1.9 MBbls of oil per day from 52 active producing wells. We estimate that we acquired approximately 7.4 MMBbls of proved oil reserves in the transaction, with proved undeveloped reserves accounting for approximately 20 percent of the total proved reserves added. In addition, we believe that there is additional upside potential which may be realized through our future work programs.

We believe the properties contain significant drilling, workover and waterflood potential which we plan to pursue along with the implementation of operational efficiencies. Drilling plans include development wells along with extensional and exploration opportunities. We anticipate that one drilling rig will be exclusively utilized for drilling activities in the Bella Vista Oeste concession during 2005. We have identified a number of workover opportunities at this time, with the work program assuming one dedicated workover rig during 2005. We have also identified a number of secondary recovery projects, including the expansion of an existing waterflood. Our 2005 plans also include a dedicated workover rig for secondary recovery activities. Funds for this acquisition were provided with cash on hand.

Divestitures

We have historically sold properties that were either marginally economical or non-strategic to our areas of operations. In 2001 and early 2002, we received proceeds of $47.1 million for properties sold primarily through public auctions in the U.S. These sales resulted in gains of $26.9 million ($16.7 million net of tax). Through these sales of 780 wells and over 600 leases in 85 fields, we significantly reduced our domestic well and lease count while reducing net U.S. production by only six percent and total net production by three percent.

In 2002, we determined that the level of investment and time horizon required to continue the development of our interests in Ecuador and Trinidad were inconsistent with the timing of our desire to reduce leverage. These assets, along with our remaining heavy oil properties in the Santa Maria area of southern California, were identified for sale. Our heavy oil properties in the Santa Maria area were sold in June 2002 for $9.5 million in cash and a note receivable for $6 million bearing monthly payments of $360,000, plus interest, with final maturity in June 2003. We received a cash payment as final settlement of this note in October 2002. On July 30, 2002, we completed the sale of our operations in Trinidad. We received $40 million in cash and recorded a gain of approximately $31.9 million ($14.9 million after income taxes).

On January 31, 2003, we completed the sale of our operations in Ecuador. We received $137.4 million in cash and recorded a gain of approximately $47.3 million ($9.5 million after income taxes). Also in 2003, we sold certain U.S. Mid-Continent gas properties for $30.0 million and certain non-strategic oil and gas assets in Saskatchewan and West Central Alberta, Canada for $27.9 million. We recorded losses of $1.7 million ($1.0 million after income taxes) on these sales. Combined, we estimate that the properties we sold in North America in 2003 accounted for proved reserves of 1.0 MMBbls of oil and 53.1 Bcf of gas as of the closing date of the sales and the Ecuador properties accounted for 45.3 MMBbls of oil. In total, these sales represented approximately 10 percent of our total proved reserves at the beginning of 2003.

In order to further reduce leverage and improve our financial flexibility to fund future production growth and recognizing the strong demand for producing oil and gas properties in Canada created by the acquisitive energy income trust sector, we sold all of our operations in Canada during 2004. On November 30, 2004, we completed the sale of our wholly-owned Canadian subsidiary for total consideration of $274.7 million ($241.5 million net of cash sold) and recorded an after-tax gain of $198.5 million. We estimate that at November 30, 2004, there were proved reserves of approximately 13.2 MMBOE associated with these properties. Proceeds from this sale were used to reduce debt outstanding under our revolving credit facility and fund a producing property acquisition in the U.S. (See "Acquisitions.")

Exploration and Development

We concentrate our acquisition efforts on proved producing properties that 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. We have pursued an active workover, recompletion and development drilling program on the properties we have acquired and intend to continue these activities in the future. Our exploitation staff focuses on maximizing the value of the properties within our reserve base and striving to offset normal production declines and our annual production.

Our exploration program is designed to contribute significantly to our growth. We divide the strategic objectives of our exploration program into two parts. First, in the U.S., our exploration focus is in our core areas where our geological and engineering expertise and experience are greatest. We use state-of-the-art technology, including 3-D seismic data, to identify prospects. Exploration in the U.S. is designed to generate reserve growth in combination with our development activities. In recent years, we have increased the magnitude of this program and we plan to continue this effort in the future 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. Our international exploration projects currently underway in Yemen and Bulgaria are characterized by higher potential and higher risk.

In 2004, we spent $57.1 million on workovers and recompletions. A measure of the overall success of our recompletion and workover operations during 2004 (excluding minor equipment repair and replacement) was that improved production or operating efficiencies were achieved from approximately 81 percent of such operations, which is consistent with the average of 80 percent for the last three years.

Development drilling activity is generated both through our 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 our leases currently producing oil and gas. We intend to continue to pursue development drilling opportunities which offer us potentially significant returns.

During 2004, we participated in the drilling of 142 gross (118 net) development wells, of which 133 gross (111 net) were productive. At December 31, 2004, our proved reserves included approximately 100 development or infill drilling locations on our U.S. acreage, 490 locations on our Argentine acreage, 20 locations on our Bolivian acreage and two locations on our acreage in Yemen. In addition, we have an extensive inventory of drilling locations on our existing properties that is not included in proved reserves. Included in our 2004 development drilling spending of $128.6 million was approximately $38.8 million in the U.S., $64.1 million in Argentina, $15.2 million in Yemen and $10.5 million in Canada. We also spent approximately $2.0 million on the acquisition of development seismic data and other development activities in 2004.

We spent approximately $51.7 million on exploration activities in 2004, participating in the drilling of 21 gross (13 net) exploratory wells, of which seven gross (four net) were productive. Exploration spending for 2004 included $34.6 million in the U.S., $4.1 million in Canada, $4.1 million in Argentina, $3.6 million in Yemen, $1.2 million in Bulgaria and $4.1 million in Italy. We also spent approximately $11.5 million on the acquisition of unproved acreage in 2004, primarily in the U.S.

Our total 2005 non-acquisition capital budget has been set at $250 million, which is comparable to our 2004 exploration and development spending. Planned development expenditures for 2005 are $178 million, consisting of $40 million in the U.S., $113 million in Argentina and $25 million in Yemen. The exploration portion of the 2005 capital budget of approximately $72 million includes $64 million in the U.S. and $8 million on various international projects.

Exploration and development activities for 2004 were concentrated mainly in our Argentina and U.S. core areas. The following is a brief description of significant developments in our recent exploration and development activities:

United States. We increased our U.S. oil and gas capital expenditures, excluding producing property acquisitions, in 2004, spending a total of $104.8 million, compared to $74.0 million in 2003. A significant portion of the 2004 exploration and development spending was aimed at converting proved undeveloped reserves to a proved developed producing status and other activities expected to contribute to production and reserves beyond 2004. As a result of these expenditures, including the impact of reserve revisions, we added 4.9 MMBOE to proved reserves in the U.S., replacing approximately 43 percent of 2004 U.S. production.

Our U.S. development program for 2004 included the drilling of 31 gross (26 net) development wells, of which 28 gross (23 net) were successful, representing a 90 percent net success rate. Development drilling plus other exploration activities in the Luling, Darst Creek and West Ranch fields of South Central Texas contributed to a doubling of the daily production rate in these fields over the last two years. Also, drilling and workover activity at our Main Pass 116 complex resulted in an increase in net daily production to 13.1 MMcf in December 2004 from 1.1 MMcf in January 2004. Production from these fields was a significant contributor to the revitalization of domestic production volumes in 2004.

Our 2004 U.S. development program also included 87 gross (76 net) workovers and recompletions (excluding minor equipment repair and replacement), of which 67 gross (66 net) resulted in improved production or operating efficiencies, for an 87 percent success rate.

For 2005, a capital budget of $40 million has been allocated to U.S. exploitation activities. A total of 20 net development wells is initially planned to be drilled and workovers are also planned on approximately 45 wells during the year, principally in California, Louisiana and Texas. Activity in 2005 targets the continuation of an infill drilling program at the Gilmer South field in East Texas, expanded drilling programs and workover activity in the Luling, Darst Creek and West Ranch fields in South Central Texas and workover activity at our South Pass and Main Pass complexes in South Louisiana and the federal waters in the Gulf of Mexico, respectively.

To date in the first quarter of 2005, we have returned to production approximately 4,250 net BOE per day of the total 6,100 net BOE per day of production which was temporarily shut-in due to the mudslides in California during January. We currently estimate that we will complete the remaining repair of the mudslide damage for a total cost of approximately $8.5 million early in the second quarter of 2005.

During late 2003 and the first half of 2004 we drilled four exploration wells on two offshore Texas blocks (High Island 55-L and High Island 56-L), based on a Miocene gas exploration target coupled with the redevelopment of additional Miocene oil and gas sands. Facility and pipeline construction was completed in mid-2004 with an initial net daily production rate of approximately 10 MMcf contributing to a growth in our gas production during the third quarter of 2004.

In total for 2004, we drilled 10 exploration wells and recorded a success rate of 40 percent. Two Miocene prospects were drilled at Matagorda Island 639 and 640 during the second half of 2004 with both encountering apparent pay sands. We hold a 25 percent working interest in this offshore Texas prospect and expect these wells to be brought on line with the installation of production facilities anticipated in mid-2005.

Also during 2004, we initiated an exploration program focused on the longer-term development and production of natural gas from unconventional resources in the U.S., such as gas produced from shale, gas produced from coal and basin-centered gas produced from unusually tight sands. Unlike conventional exploration plays, the presence of hydrocarbons is not the highest element of risk. Rather, often the existence of hydrocarbons is known from wells drilled in prior years but the design of a cost effective method of economic development and extraction represent the greatest risk. Advances in fracture stimulation techniques coupled with the prospect of a continued elevated price for domestic natural gas have combined to make these resources economically viable to produce. However, much remains to be understood industry-wide regarding the factors which control the economic development of unconventional gas resources. The potential reward of pursuing an unconventional gas resource program is that if a play concept can be commercially produced, it has the capacity to be repeated multiple times over a large area with relatively low risk similar to mining. Throughout the year, we evaluated numerous unproven unconventional resource plays and selected a minimum of four plays to test during 2005.

We began 2005 with an inventory of 13 domestic exploration prospects and a capital budget of $64 million. The focus of our domestic exploration activity is split between conventional exploration targeting the Texas Gulf Coast and onshore unconventional gas resource plays. Twenty-six million dollars has been allocated to the unconventional gas resource exploration program to drill 10 wells during 2005 to test a minimum of four play concepts identified during 2004. In one of these plays, located in the Palo Duro basin of Texas, we have secured a substantial leased and optioned position in excess of 128,000 acres. The first of two planned exploratory wells to evaluate the commercial potential of the play has been drilled and is being evaluated. The second well is currently being drilled. We own working interests in this venture which range between 65 and 75 percent.

An additional $38 million has been allocated to conventional exploration activities primarily targeting natural gas that can be brought to production quickly. This endeavor anticipates drilling 10 exploration wells to test prospects primarily located in the onshore and offshore Texas Gulf Coast. These projects are similar geologically to plays in which we were successful during 2004. We also control a 53 percent working interest in an opportunity to redevelop a Frio gas field with exploration upside in the onshore Texas Gulf Coast. A 3-D seismic survey of the area is scheduled to be completed during the second quarter of 2005 with drilling anticipated to commence in the third quarter.

Argentina. During 2004, we continued our successful growth program in Argentina. Non-acquisition capital spending of $93.2 million focused on drilling to convert proved undeveloped reserves to proved developed producing reserves and on secondary recovery activities, which we expect to contribute to production and reserves in the future. Reserve additions excluding purchases of reserves, net of reserve revisions, were 7.6 MMBOE replacing 67 percent of 2004 Argentina production.

A total of 81 gross (79 net) development wells was drilled at a success rate of 96 percent. A fifth drilling rig was added during the fourth quarter, reflecting the highest number of drilling rigs working since we began operations in Argentina. As a result of the revitalized drilling campaign and the acquisition in September of nearby properties with net oil production of 1.9 MBbls per day, net daily oil production now exceeds 31.0 MBbls. This is an all-time high level of oil production for us in Argentina.

We expect the business outlook for Argentina in 2005 to continue to be favorable and as a result, we anticipate additional production growth from Argentina in 2005. This expectation is supported by a capital budget of $113 million, which is a 21 percent increase over 2004 actual spending. Our 2005 budget includes drilling 110 development wells and performing 89 workovers. Our budget also includes the implementation of four waterflood projects which are targeted to contribute to production in 2005 and beyond.

Additionally, since our drilling program relies heavily on the interpretation of 3-D seismic data to aid in the optimum placement of wells, we plan to continue our program of recording 3-D seismic data during 2005. We believe this will allow us to continue to select drilling locations with higher initial production rates and higher ultimate oil recoveries than could otherwise be achieved. During 2004, additional 3-D surveys in Cerro Overo, Canadon Leon, Tres Picos and Cerro Wenseslao were completed with an additional 198,000 acres of data recorded.

The 3-D seismic activity planned in the 2005 budget will add approximately 90,000 acres in the San Jorge Basin of additional coverage. Once these programs are completed, approximately 64 percent of our total acreage in the San Jorge Basin will be covered by 3-D seismic data. We also have areas in the Cuyo Basin with 29 percent 3-D seismic coverage and the Neuquen Basin with no 3-D seismic coverage to date. Upon completion of the 2005 activity in progress, we will have 3-D data covering approximately 58 percent of all of our operated acreage in Argentina.

The number of development drilling locations in Argentina has increased substantially in recent years, from 331 at December 31, 2001, to 490 at December 31, 2004, due to a combination of development drilling and workover results integrated with interpretation of 3-D seismic data.

Bolivia. The focus for our operations in Bolivia continues to be on maximizing gas sales to existing markets and the development of new gas markets. During 2004, we saw a significant increase in gas production as we were able to support the additional demand for imported gas by Argentina. We did not have any capital expenditures during 2004 and do not anticipate any significant capital expenditures in Bolivia during 2005.

Yemen. On October 15, 2003, the Republic of Yemen's Ministry of Oil and Minerals approved our S-1 Damis block development plan covering 285,000 acres for a term of 20 years. This plan follows the Lam sand discovery made by the An Nagyah #2 well in December 2002, which was further delineated in 2003 with the drilling of the An Nagyah #3 and #4 wells. We increased our Yemen oil and gas capital expenditures in 2004, spending a total of $33.7 million compared to $12.5 million in 2003.

During 2004, we successfully drilled and completed eight consecutive development and appraisal wells in our An Nagyah field contributing to a 90 percent overall success rate for the year. Productive capacity from the An Nagyah wells is now approximately 12,000 Bbls (6,250 Bbls net) of oil per day. Oil production in Yemen made its initial contributions in the second quarter of 2004 and due to the successful development program in 2004, our daily production for the fourth quarter of 2004 averaged approximately 5,800 Bbls (3,028 Bbls net) before the impact of changes in inventories. Currently, production is trucked to a nearby existing pipeline and sent to an export facility. Work began in late 2004 on the construction of a permanent pipeline and central processing facility that is slated to have initial gross daily capacity of 10,000 Bbls of oil and is expected to be completed mid-2005.

We anticipate spending $31 million in Yemen during 2005 on development and exploration activities. Approximately $25 million of this spending will be for the completion of our production facilities and the drilling of four additional wells in the An Nagyah field in order to complete the development of the field. We will also continue to pursue our exploration program in Block S-1 and have allocated approximately $6 million for 2005. The Malaki exploration prospect was drilled in early 2005 but was unsuccessful. We anticipate the drilling of one additional exploration well and to continue assessing further development of our Harmel discovery.

Canada. In 2004, we significantly curtailed our capital spending as the result of disappointing operational results in 2003. Our total capital expenditures in Canada during 2004 were $17.7 million of which $11.8 million was for development projects and $5.9 million was spent on exploration activities. We drilled 29 gross (12 net) wells during 2004, 21 gross (seven net) of which were productive. For 2004, we added 1.8 MMBOE of reserves as a result of our activities replacing 56 percent of the production in Canada for 2004. On November 30, 2004, we sold all of our interests in Canada for total consideration of $274.7 million. (See "Divestitures.")

Bulgaria. We have been awarded an exploration permit for the Bourgas-Deep Sea block in the exclusive economic zone of the Republic of Bulgaria in the western Black Sea. The permit's initial exploration period expires in December 2005 and has provisions for extension. We have a 100 percent working interest and are the operator of this unexplored block that encompasses nearly 1.3 million acres (5,110 square kilometers). We acquired 1,575 kilometers of 2-D seismic data in 2003, and during 2004 completed detailed mapping of an identified large structural lead. During 2005, we expect to secure participation by an industry partner with deep water experience to drill and operate this prospect.

Oil and Gas Properties

At December 31, 2004, we owned and operated domestic producing properties in nine states, with our U.S. proved reserves located primarily in four core areas: West Coast, Gulf Coast, East Texas and Mid-Continent. In addition, we established core areas in Argentina during 1995, Bolivia during 1996 and Yemen during 2004. As of December 31, 2004, we operated 3,972 gross (3,804 net) productive wells and also owned non-operating interests in 486 gross (124 net) productive wells. We continuously evaluate the profitability of our oil, gas and related activities and we have a policy of divesting ourselves of unprofitable leases or areas of operations that are not consistent with our operating philosophy. (See "Divestitures.")

The following table sets forth estimates of our proved oil and gas reserves at December 31, 2004. The reserves are primarily estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina and Yemen and DeGolyer and MacNaughton for Bolivia. Fields comprising a total of 15.3 MMBOE, or four percent of our total proved reserves, are estimated by us.

	Oil (MBbls)			Gas (MMcf)			MBOE
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Total
West Coast	48,514	3,923	52,437	83,435	3,821	87,256	66,980
Gulf Coast	27,473	4,308	31,781	88,043	26,360	114,403	50,848
East Texas	5,406	439	5,845	53,300	9,657	62,957	16,338
Mid-Continent	748	63	811	14,851	1,861	16,712	3,596
Total U.S.	82,141	8,733	90,874	239,629	41,699	281,328	137,762
Argentina	108,692	86,280	194,972	42,371	88,470	130,841	216,779
Bolivia	3,723	1,868	5,591	281,167	146,694	427,861	76,901
Yemen	4,786	1,011	5,797	-	-	-	5,797
Total Company	199,342	97,892	297,234	563,167	276,863	840,030	437,239

Estimates of our 2004 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.

Proved reserves at December 31, 2004, include 49.2 MMBbls of oil and 9.9 Bcf of gas (50.9 MMBOE) related to the 10 year extension periods contained in our Argentina concession agreements. Proved developed reserves at December 31, 2004, include 25.6 MMBbls of oil and 0.4 Bcf of gas (25.6 MMBOE) related to these extension periods. Upon approval by the government, the extension periods begin in 2015 through 2017, depending on the effective date each concession agreement was granted. We believe, based on historical precedent, that such extensions will be obtained as a matter of course.

Our proved developed non-producing reserves are largely concentrated behind-pipe in fields which we operate. Proved undeveloped reserves are predominantly concentrated in development drilling locations and secondary recovery projects, most of which we operate.

The following is a brief discussion of our oil and gas operations in our core areas:

West Coast Area. The West Coast area includes oil and gas properties located primarily in Kern and Ventura counties and the Sacramento Basin of California. The Stevens, Forbes and Grubb formations are the dominant producing reservoirs on our acreage in California with well depths ranging from 800 feet to 14,300 feet. As of December 31, 2004, the area comprised 15 percent of our total proved reserves and 49 percent of our U.S. proved reserves. We currently operate 1,213 gross (1,182 net) productive wells in this area and we own an interest in 103 gross (eight net) productive wells operated by others. During 2004, net daily production for this area averaged approximately 11,700 BOE, or 38 percent of our total net daily U.S. production. Numerous workovers and recompletion opportunities exist in the San Miguelito and Rincon fields. Additional infill drilling locations are available in the San Miguelito, Pleito Ranch, and Tejon fields. The San Miguelito field also has waterflood potential that may add significant reserves and the Antelope Hills field has oil reserves that may be added through expansions of our steamflood project.

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. The reservoirs in the coastal waters and federal waters range in age from Pliocene to middle and upper Miocene and Oligocene. Reservoirs further onshore are predominantly from Eocene and Cretaceous ages. The depths of the producing reservoirs range from 1,200 feet to 14,500 feet. At December 31, 2004, the Gulf Coast area comprised approximately 12 percent of our total proved reserves and 37 percent of our U.S. proved reserves. We currently operate 759 gross (734 net) productive wells in this area and we own an additional interest in 31 gross (seven net) productive wells operated by others. During 2004, net daily production from this area averaged approximately 14,500 BOE, or 47 percent of our total net daily U.S. production. A significant inventory of workovers and recompletions exists in Gulf Coast fields from Alabama to south Texas. Development drilling potential is also available in various 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 and Travis Peak formations are the dominant producing reservoirs on our 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 our December 31, 2004, total proved reserves and 12 percent of our U.S. proved reserves. We currently operate 537 gross (462 net) productive wells in this area and we own an interest in an additional 36 gross (five net) productive wells operated by others. During 2004, net daily production for this area averaged approximately 3,700 BOE, or 12 percent of our total net daily U.S. production. Significant infill drilling potential exists on our acreage in the South Gilmer and Southern Pine 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 our acreage in this area with well depths ranging from 1,560 feet to 17,260 feet. This area comprised one percent of our December 31, 2004, total proved reserves and three percent of our U.S. proved reserves. We currently operate 64 gross (30 net) productive wells in this area and we own an interest in an additional 67 gross (eight net) productive wells operated by others. During 2004, net daily production for this area averaged approximately 900 BOE, or three percent of our total net daily U.S. production. Projects to improve the ultimate reserve recovery exist in the Shawnee Townsite waterflood. Significant production response was observed in our Missouri Flats waterflood project during 2004 as we anticipated.

Argentina. Our Argentine properties consist primarily of 14 mature producing concessions located on the south flank of the San Jorge Basin, all of which we operate, four concessions located in the Cuyo Basin in western Argentina, two of which we operate, three concessions in the Neuquen Basin, two of which we operate and one concession in the northern flank of the San Jorge Basin which we operate. These concessions comprised approximately 50 percent of our December 31, 2004, total proved reserves. During 2004, net daily production averaged approximately 27,050 Bbls of oil, including the impact of changes in inventories, and 23.7 MMcf of gas. We currently operate 1,374 gross (1,374 net) productive wells. In addition, we own an interest in 249 gross (96 net) productive wells operated by others. At December 31, 2004, our proved reserves included approximately 490 development drilling locations on our Argentine acreage. In addition, we have an extensive inventory of workovers and development drilling locations on our Argentine properties which are not included in proved reserves.

Yemen. On October 15, 2003, the Republic of Yemen's Ministry of Oil and Minerals approved our S-1 Damis block development plan covering 285,000 acres for a period of 20 years. We have a 75 percent working interest in this block which we operate. At year-end 2004, we have 10 gross (eight net) wells capable of production from the Lam Sand in the An Nagyah field. The current productive capacity of these wells is 6,250 Bbls net (12,000 Bbls gross) per day. We produced at a curtailed average of 3,028 net Bbls per day during the fourth quarter of 2004, as the production has to be temporarily trucked to a nearby existing pipeline for export. We expect to complete the construction of permanent pipeline and processing facilities by mid-2005 which will also allow us to produce at our productive capacity. At December 31, 2004, our proved reserves were 5.8 MMBbls of oil representing one percent of our December 31, 2004, total proved reserves. Included in proved reserves are two development drilling locations in the An Nagyah field.

Bolivia. Our Bolivian properties consist of four producing concessions located in the Chaco Basin of Bolivia. We have a 100 percent working interest in the Naranjillos, Chaco Sur and Porvenir producing concessions. In the other producing concession, Nupuco, we have a 50 percent working interest. We operate all four producing concessions. These concessions comprise approximately 18 percent of our December 31, 2004, total proved reserves and include 15 gross (14 net) productive wells. Net daily production during 2004 averaged approximately 22.2 MMcf of gas and 243 Bbls of condensate. Current net daily productive capacity of our properties in Bolivia is approximately 28 MMcf of gas and 375 Bbls of condensate. We are working to develop additional gas markets, both domestic and export, to increase the level of production from our concessions.

Marketing

Generally, our U.S. oil production is sold under short-term contracts at posted prices, plus a premium in some cases, or at NYMEX prices less a specified differential. Our Argentine oil production is currently sold to Esso S.A.P.A. (the Argentine affiliate of Exxon Mobil Corporation), ENAP (the Chilean government-owned oil company) and Repsol YPF, S.A. at the spot price for West Texas Intermediate crude oil as quoted on the Platt's Crude Oil Marketwire ("West Texas Intermediate") (approximately equal to the NYMEX reference price) less a specified differential. During 2004, approximately 21 percent of our total revenues related to oil sales to ENAP and approximately 15 percent of our total revenues related to oil sales to Exxon Mobil Corporation and its affiliated companies.

In January 2002, the Argentine government devalued the Argentine peso ("peso") and enacted an emergency law that, in part, 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. In May 2004, the Argentine government increased the export tax from 20 percent to 25 percent. This tax is applied on the sales value after the tax, thus, the net effect of the 20 percent and 25 percent rates is 16.7 percent and 20 percent, respectively. In August 2004, the Argentine government further increased the export tax rates for oil exports. The export tax now escalates from 25 percent (20 percent effective rate) to a maximum rate of 45 percent (31 percent effective rate) of the realized value for exported barrels as West Texas Intermediate posted prices per Bbl increase from less than $32.00 to $45.00 and above. The export tax is deducted for income tax purposes but is not deducted in the calculation of royalty payments. The export tax expires in February 2007. Domestic Argentine oil sales, while valued in U.S. dollars, are now being paid in equivalent pesos. Export oil sales continue to be valued and paid in U.S. dollars.

We currently export approximately 35 percent of our Argentine oil production; however, in 2004 we exported approximately 48 percent. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved toward parity with the U.S. dollar denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings resulting from the devaluation of the peso on peso denominated costs and is further reduced by the Argentine income tax savings related to deducting the impact of the export tax.

On January 2, 2003, at the Argentine government's request, crude oil producers and refiners agreed to limit amounts payable for certain domestic sales occurring during the first quarter 2003 to a maximum $28.50 per Bbl. The producers and refiners further agreed that the difference between the West Texas Intermediate posted price and the maximum price would be payable once the West Texas Intermediate posted price fell below the maximum. The debt payable under the original agreement accrues interest at eight percent. The total debt will be collected by invoicing future deliveries at $28.50 per Bbl after the West Texas Intermediate posted price falls below the maximum price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for 10 consecutive days, which occurred on February 24, 2003.

On February 25, 2003, the agreement between the producers and the refiners was modified to limit the amount payable from refiners to producers for deliveries occurring between February 26, 2003, and March 31, 2003. While the $28.50 per Bbl payable maximum was maintained, under the modified terms refiners have no obligation to pay producers for sales values that exceed $36.00 per Bbl. Furthermore, interest for debts established during this period was reduced to seven percent. This agreement expired on April 30, 2004. Through December 31, 2004, the accumulated balance of amounts which we may charge to domestic oil purchasers in Argentina, if the West Texas Intermediate posted price decreases below the established maximum price in the future, was approximately $6.8 million, excluding interest. We do not have the right to invoice for such amounts until such time as the West Texas Intermediate posted price declines below the established maximum price of $28.50. Accordingly, we have adopted a revenue recognition accounting policy for this potential revenue in which we will record such revenue only upon the receipt of payment for this additional billing due to the uncertainty of recovery of such amounts and the timing thereof. During 2004, we did not record any revenue under this agreement. During 2003, we collected and recorded revenue of approximately $251,000. Such amounts represented all amounts we were entitled to invoice under the agreement. We sold approximately 0.6 MMBbls of our net Argentine oil production (approximately six percent) under this agreement in 2004.

Given the number of governmental changes during 2004 affecting the realized price we receive for our oil sales, no specific predictions can be made about the future of oil prices in Argentina; however, in the short term, we expect Argentine oil realizations to be less than oil realizations in the United States. 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.

Our U.S. 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 very little of our U.S. gas is committed to long-term fixed-price contracts, we are positioned to take advantage of future strong gas price environments, but we are also subject to any future gas price declines. Most of our Bolivian gas production is sold at average gas prices tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. Our Argentine gas is sold under spot contracts of varying lengths and, as a result of the emergency law enacted in January 2002, these contracts are now paid in pesos. This has resulted 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 is improving over time as domestic Argentine gas drilling declines and market conditions improve. Although no specific predictions can be made about future gas prices in Argentina, we expect our Argentine realized gas prices to continue to be less than U.S. realized gas prices.

Our U.S. gas marketing activities are handled by Vintage Gas, Inc., our wholly-owned gas marketing affiliate. This marketing affiliate generates a margin through the purchase and resale of both Company-produced and third party-produced gas volumes. Generally, the marketing affiliate purchases this gas on a month-to-month basis at a percentage of resale prices.

We have entered into certain firm gas transportation and compression agreements in Bolivia whereby we have committed to transport and compress certain volumes of gas at established government-regulated fees. While these fees are not fixed, they are government-regulated and therefore, we believe the risk of significant fluctuations is minimal. We entered into these arrangements to ensure our access to gas markets and we currently expect to produce sufficient volumes to utilize all of the contracted transportation and compression capacity under these arrangements. Based on the current fee level, these commitments total approximately $1.2 million in 2005, $1.3 million in 2006 and $0.3 million in each of the years 2007, 2008 and 2009.

We have also entered into "deliver-or-pay" arrangements where we have committed to deliver certain volumes of gas to third parties in Bolivia and Argentina for a specified period of time. These volumes will be sold at market prices. If the required volumes are not delivered, we must pay for the undelivered volumes at the then-current market price. Similar to the firm transportation and compression agreements, we entered into these arrangements to ensure our access to gas markets and we currently expect to produce sufficient volumes to satisfy all of our deliver-or-pay obligations. The volumes contracted under the agreement in Bolivia are 7.1 Bcf in 2005, 7.0 Bcf in 2006, 6.0 Bcf in 2007, 6.9 Bcf in 2008 and 6.9 Bcf in 2009. The volumes contracted under the agreement in Argentina are 6.1 Bcf in 2005, 3.3 Bcf in 2006, 3.6 Bcf in 2007 and 4.0 Bcf in 2008.

We have previously entered into oil and gas derivative transactions and we intend to continue to consider various derivative transactions to realize commodity prices which we consider favorable. Derivative instruments that we consider using include swaps, options (including caps, floors and collars), futures and forward contracts. The counterparties to our current derivative transactions are commercial or investment banks.

We have entered into various oil price swap agreements covering approximately 7.2 MMBbls at a weighted average NYMEX reference price of $36.31 per Bbl for various periods of 2005, 2006 and 2007. The following table reflects the barrels covered by these oil price swaps and the corresponding weighted average NYMEX reference prices by quarter:

Quarter Ending	Bbls	NYMEX Reference Price Per Bbl
March 31, 2005	1,242,000	$ 37.77
June 30, 2005	1,255,800	36.49
September 30, 2005	1,269,600	35.57
December 31, 2005	1,269,600	34.88
March 31, 2006	427,500	37.39
June 30, 2006	432,250	36.80
September 30, 2006	437,000	36.32
December 31, 2006	437,000	35.93
March 31, 2007	189,000	34.26
June 30, 2007	63,700	39.66
September 30, 2007	64,400	39.38
December 31, 2007	64,400	39.10

We have entered into various gas price swap agreements for various periods of 2005, 2006 and 2007 covering approximately 6.6 million MMBtu at a weighted average NYMEX reference price of $6.31 per MMBtu. The following table reflects the MMBtu covered by these gas price swaps and the corresponding weighted average NYMEX reference prices by quarter:

Quarter Ending	MMBtu	NYMEX Reference Price Per MMBtu
March 31, 2005	1,161,000	$ 6.65
June 30, 2005	1,173,900	6.15
September 30, 2005	1,186,800	6.17
December 31, 2005	1,186,800	6.37
March 31, 2006	243,000	6.47
June 30, 2006	245,700	6.47
September 30, 2006	248,400	6.47
December 31, 2006	248,400	6.47
March 31, 2007	225,000	6.00
June 30, 2007	227,500	6.00
September 30, 2007	230,000	6.00
December 31, 2007	230,000	6.00

We have also entered into various gas price collars for 2005 covering approximately 11.0 million MMBtu. The following table reflects the MMBtu covered by these gas price collars and the corresponding NYMEX floor and cap reference prices:

MMBtu For 2005	NYMEX Floor Reference Price Per MMBtu	NYMEX Cap Reference Price Per MMBtu
1,825,000	$ 6.00	$ 6.80
3,650,000	6.00	8.02
1,825,000	6.00	8.73
3,650,000	6.00	9.21

We have entered into basis swap agreements for all of the gas volumes covered by price swaps and price collars. 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 we have received.

Reserves

At December 31, 2004, we had proved reserves of 437.2 MMBOE, comprised of 297.2 MMBbls of oil and 840.0 Bcf of gas. Fields comprising a total of 15.4 MMBOE or four percent of our total proved reserves are estimated by us and the remainder are estimated by the independent petroleum consultants of Netherland, Sewell & Associates, Inc. for the U.S., Argentina and Yemen and DeGolyer and MacNaughton for Bolivia. No reserve estimates have been filed with any federal authority or agency other than the SEC. For additional information on our oil and gas reserves, see "Oil and Gas Properties." The following table sets forth, at December 31, 2004, the present value of future net revenues (revenues less production, development and abandonment costs) before income taxes attributable to our proved reserves at such date (in thousands):

Proved Reserves:	
Future net revenues before income taxes	$ 6,978,023
Present value of future net revenues before income taxes, discounted at 10 percent	3,739,195
Standardized measure of discounted future net cash flows	2,475,570
Proved Developed Reserves:	
Future net revenues before income taxes	$ 4,687,112
Present value of future net revenues before income taxes, discounted at 10 percent	2,756,753

In computing this data, assumptions and estimates have been utilized, and we caution against viewing this information as a forecast of future economic conditions. The estimated 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, 2004, economic conditions. The estimated future production is valued at prices prevailing at December 31, 2004. The resulting estimated future gross revenues are reduced by estimated future costs to develop and produce the proved reserves based on December 31, 2004, cost levels, but such costs do not include debt service and general corporate overhead expenses.

Our proved reserves include amounts related to the 10 year extension periods contained in our Argentina concession agreements. Upon approval by the government, the extension periods begin in 2015 through 2017, depending on the effective date each concession agreement was granted. We believe, based on historical precedent, that such extensions will be obtained as a matter of course. The extension period reserves at December 31, 2004, consisted of 49.2 MMBbls of oil and 9.9 Bcf of gas (50.9 MMBOE). The proved reserves related to the extension periods represented $827.5 million of our future net revenues before income taxes, $208.7 million of our present value of future net revenues before income taxes, discounted at 10 percent and $117.1 million of our standardized measure of discounted future net cash flows. The proved developed reserves related to the extension periods represented $386.6 million of our future net revenues before income taxes and $125.2 million of our present value of future net revenues before income taxes, discounted at 10 percent.

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 our consolidated financial statements included elsewhere in this Form 10-K.

The reserve data set forth in this Form 10-K represent 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 our consolidated financial statements included elsewhere in this Form 10-K.

Productive Wells; Developed Acreage

The following table sets forth our productive wells and developed acreage assignable to such wells at December 31, 2004:

	Developed Acreage		Productive Wells					
			Oil		Gas		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
U.S.	443,390	302,186	2,229	2,048	581	388	2,810	2,436
Argentina	241,776	205,226	1,606	1,453	17	17	1,623	1,470
Bolivia	67,336	56,216	-	-	15	14	15	14
Yemen	285,654	214,240	10	8	-	-	10	8
Total	1,038,156	777,868	3,845	3,509	613	419	4,458	3,928

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. All of our Yemen acreage is listed as developed since the entire acreage is now held by production under the terms of the concession agreement.

Undeveloped Acreage

At December 31, 2004, we held the following undeveloped acres located in the U.S., Argentina, Italy and Bulgaria.

State/Country	Gross Acres	Net Acres
Alabama	30,724	24,629
California	15,836	9,425
Kansas	1,140	1,140
Kentucky	1,112	1,112
Louisiana	16,286	3,779
New Mexico	3,238	2,611
North Dakota	1,000	269
Oklahoma	3,879	2,405
Texas	157,342	113,850
Total U.S.	230,557	159,220
Argentina	1,296,957	1,095,857
Italy	275,107	275,107
Bulgaria	1,262,707	1,262,707
Total Company	3,065,328	2,792,891

With respect to such U.S. acreage held under leases, 229,925 gross (158,853 net) acres are held under leases with primary terms that expire at varying dates through December 31, 2009, unless commercial production has commenced. The remaining 632 gross (367 net) acres expire at various times from 2011 through 2014. We have the option to relinquish portions of our undeveloped acreage in Argentina at various dates through 2007 or pay increased lease rentals. Our acreage in Italy is held under exploration concessions that expire on March 31, 2007, unless commercial quantities of hydrocarbons are found and the concessions are converted to production concessions, which have a 30-year term. We can extend the term of the exploration concessions two times for a period of three years each time. However, each time an exploration concession is extended, we must relinquish 25 percent of its area. As a result of our unsuccessful exploration efforts in 2004, we are currently evaluating our future plans for this acreage. Our acreage in Bulgaria is held under our exploration permit, which expires in December 2005, with provisions for extension.

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,		
Production:	2004	2003	2002
Oil (MBbls) -			
U.S.	6,153	6,199	6,796
Argentina (a)	9,900(b)	10,388	10,942
Bolivia (a)	89	83	118
Yemen (a)	514	-	-
Continuing operations	16,656	16,670	17,856
Canada	830	1,248	1,829
Ecuador (a)	-	114	1,174
Total	17,486	18,032	20,859
Gas (MMcf) -			
U.S.	30,459	23,097	24,841
Argentina	8,659(b)	9,838	8,630
Bolivia	8,097	6,252	6,424
Continuing operations	47,215	39,187	39,895
Canada	14,077	19,153	29,951
Total	61,292	58,340	69,846
MBOE from continuing operations	24,525	23,201	24,505
Total MBOE	27,701	27,755	32,500
Average Sales Price (including impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 29.29(d)	$ 24.98	$ 21.78
Argentina	31.74	26.14	20.98(c)
Bolivia	23.42	23.04	20.73
Yemen	39.35	-	-
Continuing operations	31.02(d)	25.70	21.28(c)
Canada	29.27	28.18	21.62
Ecuador	-	26.87	20.46
Gas (per Mcf) -			
U.S.	$ 5.55	$ 4.20	$ 2.85
Argentina	0.67(e)	0.46(e)	0.37(e)
Bolivia	1.71	2.01	1.54
Continuing operations	3.99	2.91	2.10
Canada	4.85	4.35	2.48

	Years Ended December 31,		
	2004	2003	2002
Average Sales Price (excluding impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 36.97	$ 28.23	$ 22.66
Argentina	31.74	26.14	21.06(c)
Bolivia	23.42	23.04	20.73
Yemen	39.35	-	-
Continuing operations	33.86	26.91	21.66(c)
Canada	35.48	27.90	21.62
Ecuador	-	26.87	20.46
Gas (per Mcf) -			
U.S.	$ 5.54	$ 4.81	$ 2.94
Argentina	0.67(e)	0.46(e)	0.37(e)
Bolivia	1.71	2.01	1.54
Continuing operations	3.98	3.27	2.16
Canada	4.85	4.67	2.49
Production Costs (per BOE):			
U.S.	$ 9.43	$ 9.16	$ 8.05
Argentina	9.13	6.96	5.40
Bolivia	3.20	4.01	3.64
Yemen	8.13	-	-
Continuing operations	8.90	7.77	6.52
Canada	12.49	8.91	6.61
Ecuador	-	6.50	7.68

(a) Oil production (in MBbls) before the impact of changes in inventories:

	Years Ended December 31,		
	2004	2003	2002
Argentina	10,347(b)	10,273	10,771
Bolivia	94	83	95
Yemen	561	-	-
Ecuador	-	114	1,191

(b) Argentina production for the year ended December 31, 2004, is estimated to have been reduced by 527 MBbls of oil and 429 MMcf of gas, or 598 MBOE, as the result of a labor strike and problems at a major oil loading facility.

(c) Reflects the impact of the one-time government-mandated forced settlement of domestic Argentine oil sales which decreased the amounts for Argentina and total continuing operations average oil prices per Bbl for the year ended December 31, 2002, by $0.73 and $0.41, respectively.

(d) The average oil sales price per Bbl for the U.S. for the year ended December 31, 2004, does not reflect a realized loss of $1.78 per Bbl. The average oil sales price per Bbl for continuing operations for the year ended December 31, 2004, does not reflect a realized loss of $0.66 per Bbl. These losses have been reflected in non-operating expense as they relate to settlements on economic hedges. Economic hedges are derivative financial instruments, intended to hedge a specific exposure, that do not qualify or ceased to qualify for hedge accounting under Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended, "SFAS 133").

(e) Gas sales in Argentina during 2004, 2003 and 2002 were primarily billed and collected in Argentine pesos. The amount presented above represents the U.S. dollar equivalent price based on the average exchange rate for the period. Significant devaluation of the Argentine peso occurred during 2002. Although such sales are now substantially billed in U.S. dollar terms, the market price for gas continues to be less than 2001 levels.

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

Drilling Activity

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

	Years Ended December 31,					
	2004		2003		2002	
	Gross	Net	Gross	Net	Gross	Net
Development:						
United States -						
Productive	28	23.31	26	22.71	2	1.42
Non-Productive	3	2.50	5	3.64	-	-
Argentina -						
Productive	78	75.60	67	65.80	20	18.00
Non-Productive	3	3.00	1	1.00	-	-
Yemen						
Productive	8	6.00	-	-	-	-
Non-Productive	-	-	-	-	-	-
Canada -						
Productive	19	5.60	24	13.40	39	28.70
Non-Productive	3	1.80	1	1.00	10	8.40
Ecuador -						
Productive	-	-	-	-	3	2.15
Non-Productive	-	-	-	-	-	-
Total	142	117.81	124	107.55	74	58.67
Exploratory:						
United States -						
Productive	4	2.15	1	0.33	1	0.35
Non-Productive	6	3.26	1	0.42	1	0.25
Argentina						
Productive	-	-	-	-	-	-
Non-Productive	1	0.40	-	-	-	-
Yemen -						
Productive	1	0.75	3	2.25	1	0.75
Non-Productive	1	0.75	-	-	1	0.75
Italy -						
Productive	-	-	-	-	-	-
Non-Productive	1	1.00	-	-	-	-
Canada -						
Productive	2	1.10	2	0.70	17	13.60
Non-Productive	5	3.40	5	4.00	19	18.20
Total	21	12.81	12	7.70	40	33.90
Total:						
Productive	140	114.51	123	105.19	83	64.97
Non-Productive	23	16.11	13	10.06	31	27.60
Total	163	130.62	136	115.25	114	92.57

The above well information excludes wells in which we have only a royalty interest.

At December 31, 2004, we were a participant in the drilling, completion or evaluation of 34 gross (29 net) wells. All of our drilling activities are conducted with independent contractors. We do not own any drilling equipment.

Seasonality

Historically, our results of operations are somewhat seasonal due to seasonal fluctuations in the price for gas with gas prices having been generally higher in the winter months. 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. The production of natural gas is generally not directly affected by seasonal swings in demand, except in Argentina and Bolivia. However, we may decide during periods of low commodity prices to decrease development activity, which can result in decreased gas production volumes. Production of oil usually is not affected by seasonal swings in demand or in market prices.

Competition

Competition in the oil and gas industry is intense. In seeking to acquire desirable producing properties, new leases and exploration prospects and in marketing oil and gas, we face 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 us. Alternative fuel sources 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 oilfield equipment, including drilling rigs and tools. We are dependent upon independent drilling contractors to furnish rigs, equipment and tools to drill the wells we operate. The current environment of higher prices for oil and gas production is causing increased oilfield activity. Increased competition for these items as well as for drilling and workover rigs, in particular, has resulted in increased costs of operations and may impact the timing of our planned projects.

Regulation

Domestic Operations. 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, we are unable to predict the future cost or impact of complying with such regulations.

Our exploration and production 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. Our 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 we can produce from our wells and the number of wells or the locations at which we 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 our exploration, development and production operations. For example, the discharge or substantial threat of a discharge of oil by us into U.S. waters or onto an adjoining shoreline may subject us 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 us. Our operations generally will be covered by insurance which we believe 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 liabilities we may incur. We are also subject to laws and regulations concerning occupational safety and health. It is not anticipated that we will be required in the near future to expend any amounts that are material in the aggregate to our overall operations by reason of environmental or occupational safety and health laws and regulations, but because such laws and regulations are frequently changed, we are unable to predict the ultimate cost of compliance.

Certain of our 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, we do 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 our shares by citizens of foreign countries who are not deemed to be reciprocal under such Act could have an impact on our ownership of federal leases.

Federal legislation and regulatory controls have historically affected the price of the gas we produce and sell and the manner in which our 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. Although the regulations do not directly regulate gas producers such as us, 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 our marketing activities.

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. On the other hand, interstate transmission facilities are 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 our gathering facilities. While the FERC has not issued any order or opinion declaring our facilities as gathering rather than transmission facilities, we believe 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, some states enacted and others continually consider statutory and/or regulatory provisions to regulate gathering systems. Our 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.

Foreign Operations. Our operations in Argentina are subject to the laws and regulations of the country. 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 we receive for oil and gas we produce and sell; (ii) the timing and amount of repatriations of cash to the U.S.; (iii) the amount of permitted export sales; (iv) the Argentine banking system; (v) our asset valuations; and (vi) peso-denominated monetary assets and liabilities. (See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk - Foreign Currency and Operations Risk.")

Our operations in Bolivia, Yemen and Bulgaria 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 our operations.

Risk Factors

The nature of our business activities and operations subjects us to a number of risks and uncertainties. If any of the events described below were to occur, they could have a material adverse effect on our 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, our financial results.

Our revenues, operating results, cash flows 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 we currently receive for our production are higher than 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 our cash flows and profitability. The substantial and extended decline in oil and gas prices during 1998 and 1999 adversely affected our financial condition and results of operations. A sustained period of low prices could have a material adverse effect on our 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 our 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 our ability to market our oil and gas production, including:

- capacity and availability of oil and gas gathering systems and pipelines;
- effects of foreign, 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 our level of capital expenditures, reserve estimates and borrowing capacity.

Lower oil and gas prices, such as those we experienced in 1998 and the first half of 1999, have various adverse effects on our business, including reducing cash flows which, among other things, have caused us in the past, and may cause us in the future, to decrease our capital expenditures. A smaller capital expenditure program may adversely affect our ability to increase or maintain our reserve and production levels. Lower prices may also result in reduced reserve estimates, 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 we recorded a significant non-cash charge for the impairment of oil and gas properties due to lower oil and gas prices.

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

Our future performance depends on our ability to find or acquire additional oil and gas reserves that are economically recoverable.

Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in oil and gas production and lower revenues and cash flows from operations. We have historically succeeded in substantially replacing reserves through acquisitions, exploration and development. We have conducted such activities on our existing oil and gas properties as well as on newly acquired properties. We may not be able to continue to replace reserves from such activities at acceptable costs. Lower oil and gas prices may further limit the types of reserves that can be developed at acceptable costs. Lower prices also decrease our cash flows and may cause us to reduce capital expenditures. The business of exploring for, developing or acquiring reserves is capital intensive. We may not be able to make the necessary capital investments to maintain or expand our oil and gas reserves if cash flows from operations are reduced and external sources of capital become limited or unavailable. In addition, exploration and development activities 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.

We are continually identifying and evaluating acquisition opportunities, including acquisitions that would be significantly larger than those we have consummated to date. We cannot ensure that we will successfully consummate any acquisition, that we will be able to acquire producing oil and gas properties that contain economically recoverable reserves or that any acquisition will be profitably integrated into our operations.

Acquisitions carry unknown risks including the potential for environmental problems.

Our focus on acquiring producing oil and gas properties may increase our potential exposure to liabilities and costs for environmental and other problems existing on such properties. We expect to continue to focus, as we have done in the past, on acquiring producing oil and gas properties to replace reserves. Although we perform reviews of the acquired properties that we believe are consistent with industry practice, such reviews are inherently incomplete. In general, it is not feasible to perform an in-depth review of each individual property being acquired. Ordinarily, we focus our review efforts on the higher-valued properties and sample 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 us 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 negative revisions to reserve estimates and oil and gas price declines may lead to impairment of oil and gas assets.

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. 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 estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based on 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 uneconomical to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it 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, we recorded a significant non-cash charge for the impairment of proved oil and gas properties in the fourth quarter of 1998 due to lower oil and gas prices and we recorded significant non-cash charges for the impairment of proved oil and gas properties in the fourth quarter of 2002, in the second, third and fourth quarters of 2003 and in the fourth quarter of 2004 due to reserve revisions that resulted from additional geological, geophysical and engineering information and from revised production projections.

Our 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 our total assets. We have international operations in Argentina, Bolivia, Yemen and Bulgaria. For 2004, our operations in Argentina accounted for approximately 41 percent of our revenues from continuing operations and 38 percent of our total assets. During 2004, our operations in Argentina represented our only foreign operation accounting for more than 10 percent of our revenues from continuing operations or total assets. We continue to identify and evaluate international opportunities, but currently have no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, our 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.

Our foreign properties, operations or investments in Argentina, Bolivia, Yemen and Bulgaria may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors. For example:

- local political and economic developments could restrict or increase the cost of our foreign operations;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive tax claims could increase costs of our foreign operations;
- expropriation of our property could result in loss of revenue, property and equipment;
- civil uprisings, riots, terrorist attacks and wars could make it impractical to continue operations, adversely affect both budgets and schedules and expose us to losses;
- import and export regulations and other foreign laws or policies could result in loss of revenues;
- repatriation levels for export revenues could restrict the availability of cash to fund operations outside a particular foreign country; and
- laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict our ability to fund foreign operations or may make foreign operations more costly.

Particularly, our Bolivian projects are dependent, in part, on the continued operation of the Bolivia-to-Brazil gas pipeline and the further development of gas markets in South America. The operation of this pipeline and the development of markets are subject to various factors outside of our control. In addition, in the event of a dispute arising from foreign operations, we 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. We may also be hindered or prevented from enforcing our rights with respect to actions taken by a foreign government or its agencies.

The Argentine 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 we receive for oil and gas that we produce and sell;
- the timing of repatriations of cash to the U.S.;
- the amount of permitted export sales;
- the Argentine banking system;
- our 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.

Our derivative transactions may expose us to the risk of financial loss in certain circumstances.

We have previously entered into oil and gas derivative transactions and intend to continue to consider various derivative transactions to realize commodity prices which we consider favorable. The impact of changes in market prices for oil and gas on the average oil and gas prices we receive may be reduced based on the level of our derivative transactions that qualify for hedge accounting treatment. These derivative transactions may limit our potential gains if the market prices for oil and gas were to rise substantially over the price established by the derivative instrument. In addition, our derivative transactions expose us to the risk of financial loss in certain circumstances, including instances in which:

- production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the accounting hedge arrangement; or
- the counterparties to our derivative transactions fail to honor their financial commitments.

We currently have price swap agreements covering 7.2 MMBbls of oil for various periods in 2005, 2006 and 2007 at a weighted average NYMEX reference price of $36.31 per Bbl and 6.6 million MMBtu of gas for various periods of 2005, 2006 and 2007 at a weighted average NYMEX reference price of $6.31 per MMBtu. We also have gas price collars covering approximately 11.0 million MMBtu with NYMEX floor reference prices of $6.00 per MMBtu and NYMEX cap reference prices ranging from $6.80 to $9.21 per MMBtu.

Uninsured risks associated with our operations could result in a substantial financial loss.

Our 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 our operations and substantial losses to us. In accordance with customary industry practice, we maintain 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 our financial position and results of operations.

Governmental and environmental regulations could adversely affect our business.

Our business is subject to certain foreign, federal, state and local laws and regulations. These laws and regulations involve the exploration for, development, production and marketing of oil and gas, as well as taxation, 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 our oil and gas wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could decrease our revenues.

Our operations are subject to complex environmental laws and regulations adopted by the various jurisdictions where we operate. We 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. We 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, we cannot ensure that laws and regulations enacted in the future, including changes to existing laws and regulations, will not adversely affect our business. In addition, because we acquire interests in properties that have been previously operated by others, we may be liable for environmental damage caused by such former operators.

Industry competition may impede our growth.

The oil and gas industry is highly competitive, and we may not be able to compete successfully or grow our business. We compete 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. We also compete 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 us. We may not be able to successfully expand our business or attract or retain qualified employees.

Employees

We employ approximately 230 full-time people in our Tulsa office whose functions are associated with management, engineering, geology, land, legal, accounting, financial planning and administration. In addition, approximately 165 full-time employees are responsible for the supervision and operation of our U.S. field activities. We also employ approximately 290 people for the management and operation of our properties in Argentina, Bolivia and Yemen. We believe our relations with our employees are excellent.

Item 3. Legal Proceedings.

We are a named defendant in lawsuits and are 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 us cannot be predicted with certainty, we believe the likelihood of a material adverse effect on our financial position or results of operations resulting from the resolution of such legal proceedings is remote.

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

There were no matters submitted to our stockholders during the fourth quarter of the fiscal year ended December 31, 2004.

Item 4A. Executive Officers of the Registrant.

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

Name	Age	Position
Charles C. Stephenson, Jr.	68	Director, Chairman of the Board of Directors, President and Chief Executive Officer
William L. Abernathy	53	Director, Executive Vice President and Chief Operating Officer
William C. Barnes	50	Director, Executive Vice President, Chief Financial Officer, Secretary and Treasurer
Larry W. Sheppard	50	Senior Vice President - New Ventures
Kellam Colquitt	57	Vice President - Exploration
Robert W. Cox	59	Vice President - General Counsel
Murphy B. Herrington	46	Vice President - Acquisitions
J. Chris Jacobsen	49	Vice President - U.S. Operations
Andy R. Lowe	53	Vice President - Marketing
Michael F. Meimerstorf	48	Vice President and Controller
Robert E. Phaneuf	58	Vice President - Corporate Development
Gary A. Watson	47	Vice President - International

Mr. Stephenson, our co-founder, has been a Director since June 1983 and Chairman of our Board of Directors since April 1987. He assumed the position of President and Chief Executive Officer on February 18, 2004. He was previously our Chief Executive Officer from April 1987 to March 1994 and our President 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 44 years of oil and gas experience.

Mr. Abernathy has been a Director since October 1999, and an Executive Vice President and our Chief Operating Officer since December 1997. He was our Senior Vice President—Acquisitions from March 1994 to December 1997, our Vice President—Acquisitions from May 1990 to March 1994 and our Manager—Acquisitions 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, and our Treasurer and Secretary since April 1987, an Executive Vice President since March 1994 and our Chief Financial Officer since May 1990. He was also a Senior Vice President from May 1990 to March 1994 and our Vice President—Finance 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. Sheppard has been our Senior Vice President—New Ventures since July 2003. He was our Vice President - New Ventures from May 2001 to July 2003. From November 1994 to May 2001, he was our Vice President—International. 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. Colquitt has been our Vice President—Exploration since May 2001. From April 2000 to May 2001, he was our General Manager—North American Exploration. 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 our Vice President—General Counsel 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. Herrington has been our Vice President—Acquisitions since June 2003. He was our Acquisitions Technical Manager from May 1998 to June 2003 and an Acquisitions Engineer with us from March 1993 to May 1998. From December 1980 to March 1993, he was employed by Exxon Company USA, serving as a Reservoir Engineer. He has a B.S. Degree in Chemical Engineering from Mississippi State University.

Mr. Jacobsen has been our Vice President—U.S. Operations since November 2002. Mr. Jacobsen was Senior Vice President of various exploitation and exploration staffs for KCS Energy, Inc. and Medallion Production Company, independent oil and gas companies, from 1994 to 2002. He was Senior Vice President at Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, where he managed engineering and geological teams from 1982 to 1994. From 1977 to 1982, he held various engineering and supervisory assignments with Exxon Company USA in Lafayette and New Orleans, Louisiana. He has a B.S. Degree in Chemical Engineering from Rose Hulman Institute of Technology.

Mr. Lowe has been our Vice President—Marketing since December 1997. He was our General Manager—Marketing from July 1992 to December 1997. He was President of Quasar Energy, Inc. from November 1990 to July 1992, providing downstream natural gas marketing services. 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 our Controller since January 1988 and a Vice President since May 1990. He was our Accounting Manager 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 our Vice President—Corporate Development 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. Watson has been our Vice President—International since January 2005. From June 2001 to January 2005, he was our Vice President—Canadian Operations. He was our General Manager—Latin American Operations 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, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Our 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 our common stock, as reported in the New York Stock Exchange composite transactions, and the cash dividends paid per share of our common stock for the periods indicated:

	High	Low	Dividends Paid
2004			
First Quarter	$ 15.60	$ 11.52	$ 0.045
Second Quarter	17.58	13.61	0.045
Third Quarter	20.53	15.11	0.050
Fourth Quarter	24.50	19.10	0.050
2003			
First Quarter	$ 11.46	$ 9.00	$ 0.040
Second Quarter	12.34	9.10	0.040
Third Quarter	12.10	10.51	0.045
Fourth Quarter	12.93	10.14	0.045

Substantially all of our stockholders maintain their shares in "street name" accounts and are not, individually, stockholders of record. As of December 31, 2004, our common stock was held by 199 holders of record and approximately 12,250 beneficial owners.

We began paying a quarterly cash dividend in the fourth quarter of 1992 and we 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, we suspended our regular quarterly cash dividend for the remainder of 1999. We re-instituted the payment of dividends beginning in the first quarter of 2000 with a $0.025 per share cash dividend and we expect to continue paying a regular quarterly cash dividend.

Our credit arrangements (including the indentures for our outstanding senior and senior subordinated indebtedness) contain certain restrictions on distributions to common stockholders, including the payment of cash dividends. However, none of these restrictions materially limit our ability to pay dividends at this time. Subject to these restrictions in our credit arrangements, the determination of the amount of future cash dividends, if any, to be declared or paid, will depend on, among other things, our financial condition, funds from operations, the level of our capital expenditures and our future business prospects.

Item 6. Selected Financial Data.

SELECTED FINANCIAL AND OPERATING DATA

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands, except per share amounts and operating data)				
Statement of Operations Data:					
Oil, condensate and NGL sales	$ 516,756	$ 428,350	$ 380,032	$ 426,067	$ 476,278
Gas sales	188,582	114,049	83,902	194,108	171,177
Gas marketing revenues	71,476	70,633	54,391	103,087	128,836
Total revenues	778,180	614,747	518,978	723,535	778,014
Operating and administrative costs	349,876	300,483	251,380	313,285	316,436
Exploration costs	31,993	21,607	22,942	15,942	22,486
Depreciation, depletion and amortization	103,202	87,814	104,872	113,541	97,444
Impairment of proved oil and gas properties	6,049	6,050	16,972	10,155	225
Accretion	6,626	5,980	-	-	-
Interest	51,815	69,834	77,314	64,181	48,412
Loss on early extinguishment of debt	9,903	6,909	8,154	-	-
Income from continuing operations before cumulative effect of changes in accounting principles	125,441	59,494	34,971	159,572	170,974
Income (loss) from discontinued operations, net of income taxes	207,151	(307,520)	(118,088)	(26,065)	25,933
Income (loss) before cumulative effect of changes in accounting principles	332,592	(248,026)	(83,117)	133,507	196,907
Net income (loss)	332,592	(240,907)	(143,664)	133,507	195,893
Income per share from continuing operations before cumulative effect of changes in accounting principles:					
Basic	1.93	0.93	0.55	2.53	2.73
Diluted	1.91	0.92	0.55	2.49	2.67
Income (loss) per share before cumulative effect of changes in accounting principles:					
Basic	5.11	(3.87)	(1.31)	2.12	3.15
Diluted	5.06	(3.85)	(1.31)	2.09	3.08
Income (loss) per share:					
Basic	5.11	(3.76)	(2.27)	2.12	3.13
Diluted	5.06	(3.74)	(2.26)	2.09	3.06
Dividends declared per share	0.20	0.18	0.16	0.14	0.14
Balance Sheet Data (end of year):					
Total assets	$ 1,644,892	$ 1,454,259	$ 1,775,804	$ 2,107,902	$ 1,352,002
Long-term debt	549,949	699,943	883,180	1,010,673	464,229
Stockholders' equity	683,678	422,486	570,992	729,443	624,857

	Years Ended December 31,				
	2004	2003	2002	2001	2000
	(In thousands, except per share amounts and operating data)				
Operating Data:					
Production:					
Oil (MBbls)	17,486	18,032	20,859	21,974	19,861
Gas (MMcf)	61,292	58,340	69,846	75,641	53,729
BOE	27,701	27,755	32,500	34,581	28,816
Average Sales Prices:					
Oil (per Bbl)	$ 30.94	$ 25.88	$ 21.27	$ 21.93	$ 25.55
Gas (per Mcf)	4.19	3.38	2.26	3.30	3.22
Proved Reserves (end of year):					
Oil (MBbls)	297,234	292,798	348,697	332,261	318,560
Gas (MMcf)	840,030	926,038	1,083,546	1,216,724	1,023,208
Total proved reserves (MBOE)	437,239	447,138	529,288	535,048	489,095
Present value of estimated future net revenues before income taxes discounted at 10 percent (in thousands)	$ 3,739,195	$ 3,506,125	$ 4,009,322	$ 1,914,073	$ 4,338,616
Standardized measure of discounted future net cash flows (in thousands)	2,475,570	2,382,528	2,746,257	1,438,141	2,951,121

Significant acquisitions of producing oil and gas properties during 2004 and 2001 and significant dispositions of oil and gas properties during 2004, 2003, 2002 and 2001 affect the comparability between the Financial and Operating Data for the years presented above. The statement of operations data reflect the presentation of our operations in Trinidad, Canada and Ecuador as discontinued operations for all periods. (See Note 7 to our consolidated financial statements included elsewhere in this Form 10-K.) The operating data include the results from discontinued operations for all periods.

The amounts in the "Proved Reserves (end of year)" section above include amounts related to the 10 year extension periods contained in our Argentina concession agreements. See Note 11 to our consolidated financial statements included elsewhere in this Form 10-K.

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

Overview

We are an independent energy company with operations primarily in the exploration and production and gas marketing segments of the oil and gas industry. We have operations or exploration activities in the U.S., South America, Yemen, and Bulgaria. We are focused on the acquisition of oil and gas properties which contain the potential for increased value through exploitation and exploration. In addition, we are focused on continuing to build an inventory of exploration prospects in the U.S. that may impact production in the near term as well as high potential frontier prospects that may impact production in the longer term.

During 2002 and 2003, we focused on managing our financial leverage, maintaining liquidity and positioning ourselves for long-term growth. As a result of the acquisitions in Canada and Argentina in 2001, we ended 2001 with $1.0 billion of long-term debt. Since that time, we have improved our balance sheet and leverage position by reducing long-term debt to $550 million. In addition, we have $124 million of cash at December 31, 2004. We funded this reduction in debt with proceeds from property sales and cash provided by operating activities and by reducing our capital expenditures. In addition to cash on hand, as of February 28, 2005, we have unused availability under our revolving credit facility of $296.6 million (considering outstanding letters of credit of approximately $3.4 million).

Beginning in 2003 and continuing through 2004, after achieving our goal of debt reduction, we focused on our core objectives of acquisitions, exploitation and exploration and significantly increased our capital expenditure budget. We were able to complete two acquisitions of producing properties, one in September 2004 in Argentina at a total cost of $34.9 million and one in the United States in December 2004 at a total cost of $77.2 million. This increased focus on our core objectives resulted in a significant improvement in our production levels and our operating results.

We reported net income of $332.6 million in 2004 versus a net loss of $240.9 million in 2003. Our 2004 profitability was significantly impacted by a $198.5 million after tax gain from the sale of our Canadian operations plus strong production levels in our continuing operations and higher oil and gas prices. The loss in 2003 was driven by non-cash charges for impairments of our Canadian oil and gas properties and goodwill as a result of negative revisions to our Canadian reserves. While the 2003 results were disappointing, our liquidity and financial position remained strong as these non-cash charges had no material adverse impact on our financial covenants under our debt instruments.

Our cash provided by continuing operations for 2004 was $337.6 million, which was 59 percent greater than 2003, as a result of significantly higher oil and gas prices and a six percent increase in production on a BOE basis. In addition, during 2004 we sold all of our Canadian operations generating $241.5 million of proceeds, net of cash sold, which we used to fund acquisitions and eliminate our outstanding advances under our revolving credit facility and provide available cash for future activities.

We have 437.2 MMBOE of oil and gas reserves as of December 31, 2004, reflecting the sale of 13.2 MMBOE of reserves and production of 27.7 MMBOE in 2004. Excluding the additions and revisions to our Canadian reserves, we added 29.2 MMBOE to our reserves, at a cost of $11.90 per BOE, replacing 119 percent of our production. During 2004, we increased our acquisition, exploration and development activities and we made oil and gas capital expenditures of $365.2 million, spending 108 percent of our cash provided by continuing operations.

Our focus for 2005 is to continue profitability with increased production and reserve growth from a balance of acquisitions, exploitation and exploration. We have established our 2005 non-acquisition oil and gas capital expenditure budget at $250 million, which is consistent with our spending in 2004. We expect to have sufficient internally generated cash flows to fund our non-acquisition capital expenditures. In the event we successfully secure acquisitions of oil and gas properties, we will seek appropriate levels of oil and gas price risk management and equity capital in order to maintain or improve our capital structure.

Our future financial results depend on a number of factors, including, in particular, oil and gas prices, our ability to find or acquire oil and gas reserves, access to capital, our ability to control costs and both domestic and foreign regulatory developments. Commodity prices are impacted by many factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Oil and gas prices are affected by changes in market demands, overall economic activity, political events, weather, inventory storage levels, basis differentials and other factors. As a result, we can not accurately predict future oil and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital programs, production volumes, future revenues or our ability to acquire oil and gas properties. In addition to production volumes and commodity prices, acquiring, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success.

Results of Operations

Our results of operations have been significantly affected by our success in acquiring oil and gas properties and our ability to maintain or increase production through our exploitation and exploration activities. Acquisitions of producing oil and gas properties during 2004 and significant dispositions of producing properties during 2004, 2003 and 2002 affect the comparability of operating data for the periods presented in the tables below. Fluctuations in oil and gas prices have also significantly affected our results. The following tables reflect our oil and gas production and our average oil and gas prices for the periods presented:

	Years Ended December 31,		
	2004	2003	2002
Production:			
Oil (MBbls) -			
U.S.	6,153	6,199	6,796
Argentina (a)	9,900(b)	10,388	10,942
Bolivia (a)	89	83	118
Yemen (a)	514	-	-
Continuing operations	16,656	16,670	17,856
Canada	830	1,248	1,829
Ecuador (a)	-	114	1,174
Total	17,486	18,032	20,859
Gas (MMcf) -			
U.S.	30,459	23,097	24,841
Argentina	8,659(b)	9,838	8,630
Bolivia	8,097	6,252	6,424
Continuing operations	47,215	39,187	39,895
Canada	14,077	19,153	29,951
Total	61,292	58,340	69,846
MBOE from continuing operations	24,525	23,201	24,505
Total MBOE	27,701	27,755	32,500

(a) Oil production (in MBbls) before the impact of changes in inventories:

	Years Ended December 31,		
	2004	2003	2002
Argentina	10,347(b)	10,273	10,771
Bolivia	94	83	95
Yemen	561	-	-
Ecuador	-	114	1,191

(b) Argentina production for the year ended December 31, 2004, is estimated to have been reduced by 527 MBbls of oil and 429 MMcf of gas, or 598 MBOE, as the result of a labor strike and problems at a major oil loading facility.

	Years Ended December 31,		
	2004	2003	2002
Average Sales Price (including impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 29.29(b)	$ 24.98	$ 21.78
Argentina	31.74	26.14	20.98(a)
Bolivia	23.42	23.04	20.73
Yemen	39.35	-	-
Continuing operations	31.02(b)	25.70	21.28(a)
Canada	29.27	28.18	21.62
Ecuador	-	26.87	20.46
Gas (per Mcf) -			
U.S.	$ 5.55	$ 4.20	$ 2.85
Argentina	0.67(c)	0.46(c)	0.37(c)
Bolivia	1.71	2.01	1.54
Continuing operations	3.99	2.91	2.10
Canada	4.85	4.35	2.48
Average Sales Price (excluding impact of hedges):			
Oil (per Bbl) -			
U.S.	$ 36.97	$ 28.23	$ 22.66
Argentina	31.74	26.14	21.06(a)
Bolivia	23.42	23.04	20.73
Yemen	39.35	-	-
Continuing operations	33.86	26.91	21.66(a)
Canada	35.48	27.90	21.62
Ecuador	-	26.87	20.46
Gas (per Mcf) -			
U.S.	$ 5.54	$ 4.81	$ 2.94
Argentina	0.67(c)	0.46(c)	0.37(c)
Bolivia	1.71	2.01	1.54
Continuing operations	3.98	3.27	2.16
Canada	4.85	4.67	2.49

(a) Reflects the impact of the one-time government-mandated forced settlement of domestic Argentine oil sales which decreased the amounts for Argentina and continuing operations average oil prices per Bbl for the year ended December 31, 2002, by $0.73 and $0.41, respectively.

(b) The average oil sales price per Bbl for the U.S. for the year ended December 31, 2004 does not reflect a realized loss of $1.78 per Bbl. The average oil sales price per Bbl for continuing operations for the year ended December 31, 2004, does not reflect a realized loss of $0.66 per Bbl. These losses have been reflected in non-operating expense as they relate to settlements on economic hedges. Economic hedges are derivative financial instruments, intended to hedge a specific exposure, that do not qualify or ceased to qualify for hedge accounting under SFAS 133.

(c) Gas sales in Argentina during 2002 and 2003 were primarily billed and collected in Argentine pesos. The amount presented above represents the U.S. dollar equivalent price based on the average exchange rate for the period. Significant devaluation of the Argentine peso occurred during 2002. Although such sales are now substantially billed in U.S. dollar terms, the market price for gas continues to be less than 2001 levels.

Oil Prices

Average U.S. oil prices we receive generally fluctuate with changes in the NYMEX reference price for oil. Our oil production in Argentina 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. Our Yemen oil production is sold at Dated Brent prices as quoted in Platt's Crude Oil Marketwire less a specified differential. In 2004, we experienced a 21 percent increase in our average oil price from continuing operations, including the impact of hedging activities (26 percent increase excluding hedging activities), compared to 2003. We experienced a 21 percent increase in our average oil price from continuing operations, including the impact of hedging activities (24 percent increase excluding hedging activities) in 2003 compared to 2002. Our realized average oil price from continuing operations for 2004 (before hedges) was approximately 82 percent of the NYMEX reference price, compared to 87 percent in 2003 and 83 percent in 2002.

During late 2004 and early in 2005 when the NYMEX reference price for crude oil was at or above $45 per barrel, our contract differentials on our California and Argentina properties increased, thus lowering our average realized oil prices as a percent of NYMEX. If future NYMEX reference prices stay at or above this level our realized price as a percentage of NYMEX may be lower than our previous historical relationships.

As discussed in Note 1 to our 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 February 2002, enacted an emergency law that, in part, 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. In May 2004, the Argentine government increased the export tax from 20 percent to 25 percent. This tax is applied on the sales value after the tax, thus, the net effect of the 20 percent and 25 percent rates is 16.7 percent and 20 percent, respectively. In August 2004, the Argentine government further increased the export tax rates for oil exports. The export tax now escalates from 25 percent (20 percent effective rate) to a maximum rate of 45 percent (31 percent effective rate) of the realized value for exported barrels as West Texas Intermediate posted prices per Bbl increase from less than $32.00 to $45.00 and above. The export tax is deducted for income tax purposes but is not deducted in the calculation of royalty payments. The export tax expires in February 2007. Given the number of governmental changes during 2004 affecting the realized price we receive for our oil sales, no specific predictions can be made about the future of oil prices in Argentina; however, in the short term, we expect Argentine oil realizations to be less than oil realizations in the United States. Export oil sales continue to be valued and paid in U.S. dollars. 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 Argentine oil sales, while valued in U.S. dollars, are now being paid in equivalent pesos.

We currently export approximately 35 percent of our Argentine oil production; however, in 2004 we exported approximately 48 percent. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved toward parity with the U.S. dollar-denominated export values, net of the export tax. The adverse impact of this tax has been partially offset by the net cost savings from the devaluation of the peso on peso-denominated costs and is further reduced by the Argentine income tax savings related to deducting the impact of the export tax.

On January 2, 2003, at the Argentine government's request, crude oil producers and refiners agreed to limit amounts payable for certain domestic sales occurring during the first quarter of 2003 to a maximum $28.50 per Bbl. The producers and refiners further agreed that the difference between the West Texas Intermediate posed price and the maximum price would be payable once the West Texas Intermediate posted price fell below the maximum. The debt payable under the original agreement accrues interest at eight percent. The total debt will be collected by invoicing future deliveries at $28.50 per Bbl after the West Texas Intermediate posted price falls below the maximum price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for 10 consecutive days, which occurred on February 24, 2003.

On February 25, 2003, the agreement between the producers and the refiners was modified to limit the amount payable from refiners to producers for deliveries occurring between February 26, 2003, and March 31, 2003. While the $28.50 per Bbl payable maximum was maintained, under the modified terms refiners have no obligation to pay producers for sales values that exceed $36.00 per Bbl. Through December 31, 2004, the accumulated balance of amounts which we may charge to domestic oil purchasers in Argentina, if the West Texas Intermediate posted price decreases below the established maximum price in the future, was approximately $6.8 million, excluding interest. We do not have the right to invoice for such amounts until such time as the West Texas Intermediate posted price declines below the established price cap of $28.50. Accordingly, we have adopted a revenue recognition accounting policy for this potential revenue in which we will record such revenue only upon the receipt of payment for this additional billing due to the uncertainty of recovery of such amounts and the timing thereof. During 2004, we did not record any revenue under this agreement. During 2003, we collected and recorded revenue of approximately $251,000. Such amounts represented all amounts we were entitled to invoice under the agreement. We sold approximately 0.6 MMBbls of our net Argentine oil production (approximately six percent) under this agreement in 2004.

To the extent that derivative financial instruments qualify for accounting treatment as cash flow hedges, we record the cash settlements as an adjustment to oil and gas sales. We participated in oil price swaps covering 5.6 MMBbls, 4.9 MMBbls and 4.9 MMBbls in 2004, 2003 and 2002, respectively. We accounted for all of the 2002 and 2003 oil price swaps as cash flow hedges and we accounted for 5.0 MMBbls of the 2004 oil price swaps as cash flow hedges. The impact of the cash settlements under oil price swaps accounted for as cash flow hedges are reflected in the preceding tables. The impact of the 0.6 MMBbls under the 2004 oil price swaps not accounted for as cash flow hedges did not impact reported oil sales, as these cash settlements were recorded in non-operating income or expense.

Gas Prices

Average U.S. gas prices we receive generally fluctuate with changes in spot market prices, which may vary significantly by region. Most of our Bolivian gas production is sold at average gas prices tied to a long-term contract under which the base price is adjusted for changes in specified fuel oil indexes. Our Argentine gas is sold under spot contracts of varying lengths, which, as a result of the emergency law enacted in January 2002, are now paid in pesos. This has initially resulted in a decrease in sales revenue value when converted to U.S. dollars due to the devaluation of the peso and current market conditions. Market prices for gas in Argentina have historically been significantly less than developed countries, such as the U.S. This is due primarily to limited gas markets and gas infrastructure in the region whose developed supplies have been sufficient to meet both internal demand and allow for exports to Chile. Pursuant to an emergency law passed on January 10, 2002, utility tariffs were converted to Argentine pesos and then frozen by the Argentine government. As a result, we experienced a further reduction in the prices offered for our gas production subsequent to 2001. This value may improve over time as domestic Argentine gas drilling declines and market conditions improve. Our total average gas price from continuing operations for 2004 was 37 percent higher than 2003, including the impact of hedging activities (22 percent higher excluding hedging activities), and for 2003 was 39 percent higher than for 2002, including the impact of hedging activities (51 percent higher excluding hedging activities).

We participated in gas price swaps covering 3.7 million MMBtu, 20.1 million MMBtu and 13.5 million MMBtu in 2004, 2003 and 2002, respectively. All of these gas price swaps were accounted for as cash flow hedges. The impacts of the cash settlements under these cash flow hedges on our average gas prices are reflected in the preceding tables.

Future Period Hedges

We have previously entered into oil and gas derivative transactions and we intend to continue to consider various derivative transactions to realize commodity prices which we consider favorable. We have entered into various oil price swap agreements covering approximately 7.2 MMBbls at a weighted average NYMEX reference price of $36.31 per Bbl for various periods in 2005, 2006 and 2007. We have entered into various gas price swap agreements for various periods of 2005, 2006 and 2007 covering approximately 6.6 million MMBtu at a weighted average NYMEX reference price of $6.31 per MMBtu. We have also entered into various gas price collars for 2005 covering approximately 11.0 million MMBtu with NYMEX floor reference prices of $6.00 per MMBtu and NYMEX cap reference prices ranging from $6.80 to $9.21 per MMBtu. For additional information, see "Items 1 and 2. Business and Properties - Marketing" included elsewhere in this Form 10-K. The counterparties to our current hedging arrangements are commercial or investment banks.

Relatively modest changes in either oil or gas prices significantly impact our results of operations and cash flows. However, the impact of changes in the market prices for oil and gas on our average realized prices may be reduced from time to time based on the level of our derivative transactions that qualify for hedge accounting treatment. Based on 2004 oil production from continuing operations, a change in the average oil price we realize, before hedges, of $1.00 per Bbl would result in a change in net income and revenues less production and export taxes on an annual basis of approximately $9.6 million and $15.1 million, respectively. A $0.10 per Mcf change in the average gas price we realize, before hedges, would result in a change in net income and revenues less production and export taxes on an annual basis of approximately $3.0 million and $4.6 million, respectively, based on 2004 gas production from continuing operations.

Period to Period Comparisons

The period to period comparisons presented below are significantly affected by acquisitions and dispositions we made during the periods. On July 30, 2002, we completed the sale of our operations in Trinidad. We received $40 million in cash and recorded a gain of $31.9 million ($14.9 million after income taxes). On January 31, 2003, we completed the sale of our operations in Ecuador. We received $137.4 million in cash and recorded a gain of $47.3 million ($9.5 million after income taxes). On November 30, 2004, we completed the sale of our Canadian operations. We received $274.7 million in cash and recorded a gain of $167.8 million ($198.5 million after income taxes).

Our Canadian operations began during 2000 with the acquisition of Cometra for $52 million. In May 2001, we purchased Genesis for $617 million (based on the exchange rate at date of payment). We also recognized goodwill of $175 million in the Genesis acquisition. After the Genesis acquisition, we merged Cometra into Genesis and the combined operation became our only Canadian reporting unit.

As a result of lower than planned realized gas prices in Canada and the disappointing results we experienced in our exploration and development activities, primarily in 2003, we were unable to achieve the results we anticipated when we made the acquisitions of Cometra and Genesis. As a result, we recorded impairments of all of the goodwill recorded in the Genesis acquisition and a substantial portion of our Canadian proved and unproved properties during the period of 2001 through 2003, as discussed further in Note 1 to the accompanying consolidated financial statements.

Due to the poor results of our Canadian exploration and development activities during the last half of 2003, we decided to substantially curtail exploration and development activities for our Canadian operations, which resulted in a significant reduction of our estimate of proved reserves. We had not made a decision to sell such operations at that time as we were still evaluating the best course of action to take related to such operations. During 2004, we determined that we would sell all of our Canadian operations. As a result of the improved commodity price outlook and what we believed to be a very attractive divestiture market at the time, which was being fueled by the acquisition activities of the Canadian income trusts, we recognized a gain on sale of such assets.

In accordance with the rules established by Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS 144"), our operations in Trinidad, Ecuador and Canada, along with the gains on the sales, are accounted for as discontinued operations in our consolidated financial statements. ***Accordingly, the revenues and expenses discussed below exclude the results related to our operations in Trinidad, Ecuador and Canada for all periods.***

We reported net income of $332.6 million for the year ended December 31, 2004, a net loss of $240.9 million for the year ended December 31, 2003, and a net loss of $143.7 million for the year ended December 31, 2002. Net income for the year ended December 31, 2004, included:

- income from discontinued operations of $207.0 million which includes an after tax gain on sale of our Canadian operations of approximately $198.5 million;
- a loss on early extinguishment of debt of $9.9 million ($6.0 million net of tax);
- derivative losses of $21.7 million ($13.3 million net of tax); and
- increased export taxes on export sales of Argentine crude oil of $12.0 million resulting primarily from increased export sales revenue and an increase in the export sales tax rate.

The net loss for the year ended December 31, 2003, included:

- a loss from discontinued operations of $307.5 million due primarily to a non-cash charge of $364.1 million ($210.8 million net of tax) for the impairment of Canadian proved oil and gas properties and a non-cash charge of $25.7 million for the impairment of Canadian goodwill;
- a gain of $11.2 million ($7.1 million net of tax) for the cumulative effect of a change in an accounting principle for the adoption of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, ("SFAS 143");
- a loss on early extinguishment of debt of $6.9 million ($4.2 million net of tax);
- a loss on disposition of assets of $1.2 million ($0.7 million net of tax); and
- a loss from foreign currency translations of $6.7 million.

The net loss for the year ended December 31, 2002, included:

- a loss from discontinued operations of $118.1 million due primarily to a non-cash charge of $81.7 million ($60.4 million net of tax) for the impairment of Canadian proved oil and gas properties and a non-cash charge of $76.4 million for the impairment of Canadian goodwill;
- a loss of $60.5 million for the cumulative effect of a change in an accounting principle for the adoption of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* ("SFAS 142");
- a loss on early extinguishment of debt of $8.2 million ($5.0 million net of tax); and
- a net gain on disposition of assets of $16.6 million ($10.1 million net of tax).

Oil, condensate and NGL sales. Oil, condensate and NGL sales increased $88.4 million, 21 percent, to $516.7 million for 2004 from $428.3 million for 2003 due to a 21 percent increase in our average oil price during 2004. Oil volumes sold during 2004 were essentially flat compared to 2003. Increased volumes from our Yemen operations were more than offset by reduced sales volumes in Argentina of approximately 0.5 MMBbls resulting from a labor strike and problems at a major oil loading facility. In addition, weather delays in late December, which affected shipping, resulted in an increase in Argentine crude oil inventories at December 31, 2004 of 0.4 MMBbls.

Oil, condensate and NGL sales increased $48.3 million, 13 percent, to $428.3 million for 2003 from $380.0 million for 2002 due to the offsetting effects of a 21 percent increase in our average oil price during 2003 and a seven percent decrease in our oil production. The production decline was primarily due to the sale of non-strategic U.S. oil and gas properties in June 2002 and March 2003, natural production declines and the effects of substantially curtailed capital expenditures in 2002, which resulted in significantly lower production levels at the beginning of 2003. Capital expenditures were reduced significantly as a result of our decision to use a portion of our cash flow and proceeds from asset sales to execute our debt reduction program in 2002.

Gas sales. Gas sales increased $74.6 million, 65 percent, to $188.6 million for 2004 from $114.0 million for 2003. The increase is the result of a 37 percent increase in our average gas price along with a 20 percent increase in gas production during 2004 compared to 2003. Gas production in the U.S. increased primarily as a result of exploitation successes, the most significant of which resulted from the gas recompletion and drilling activities in Texas. Bolivia gas production has also increased primarily as a result of Argentina's increased demand for imported gas. These increases were slightly offset by the production decreases of 429 MMcf of gas in Argentina related to the labor strike and major oil loading facility problems discussed above. There were no similar disruptions in 2003.

Gas sales increased $30.1 million, 36 percent, to $114.0 million for 2003 from $83.9 million for 2002 due to the offsetting effects of a 39 percent increase in our average gas price and a two percent decrease in gas production during 2003 compared to 2002. The decline in production was due primarily to the sale of non-strategic U.S. oil and gas properties in June 2002 and March 2003, natural production declines and the effects of substantially curtailed capital expenditures in 2002, as discussed above.

Production costs. Production costs increased $16.6 million, 13 percent, to $141.0 million for 2004 from $124.4 million for 2003. On an equivalent barrel basis, production costs increased by seven percent to $5.75 for 2004 from $5.36 for 2003. These increases are primarily due to costs incurred in 2004 to repair damage resulting from the October 2003 fires in California, significantly increased workover activity and higher U.S. power costs.

Production costs increased $12.5 million, 11 percent, to $124.4 million for 2003 from $111.9 million for 2002. On an equivalent barrel basis, production costs increased by 17 percent to $5.36 for 2003 from $4.57 for 2002. The increase was primarily the result of higher costs (expressed in U.S. dollars) in Argentina resulting from peso inflation and strengthening of the peso relative to the U.S. dollar. The increase was partially offset by reductions in expenses due to property sales in the U.S. during 2002 and 2003. The increase on an equivalent barrel basis was also impacted by a five percent decline in production from 2002 to 2003.

Transportation and storage costs. Transportation and storage costs increased $3.7 million, 50 percent, to $11.1 million for 2004 from $7.4 million for 2003. These increases are primarily the result of trucking costs associated with our new Yemen production area. We began incurring these costs in 2004 to deliver our product to a nearby processing facility. There was no equivalent charge in 2003. Our processing facility and pipeline is currently in the design and fabrication stage and completion of the 10,000 gross barrels per day facility is scheduled for mid-2005. Our transportation and storage costs per BOE increased from $0.32 in 2003 to $0.45 in 2004.

Transportation and storage costs increased $0.4 million, six percent, to $7.4 million for 2003 from $7.0 million for 2002. These increases are primarily due to the strengthening of the Argentine peso relative to the U.S. dollar.

Production and ad valorem taxes. Production and ad valorem taxes increased $5.5 million, 32 percent, to $23.0 million for 2004 from $17.5 million for 2003. These increases are primarily the result of higher U.S. oil and gas prices and an increase in U.S. production on an equivalent barrel basis of 12 percent during 2004.

Production and ad valorem taxes increased $2.0 million, 13 percent, to $17.5 million for 2003 from $15.4 million for 2002. These increases are primarily the result of higher U.S. oil and gas prices during 2003.

Export taxes. Export taxes in Argentina increased $12.0 million, 39 percent, to $43.0 million for 2004 from $31.0 million for 2003. While our Argentine domestic sales volumes as a percent of our total sales volumes have increased in 2004 compared to 2003, the impact of higher oil prices and the increased export tax rates in 2004 offset the decreases in export volumes. The export tax rate increased from 20 percent to 25 percent in May 2004 and was further increased in August 2004. The average effective export tax rate for 2004 on our exported volumes was 22.6 percent.

Export taxes in Argentina increased $6.2 million, 25 percent, to $31.0 million for 2003 from $24.8 million for 2002. The increase is due primarily to higher oil prices in 2003 and to the fact that export taxes were only in effect for 10 months in 2002.

Exploration costs. Exploration costs increased $10.4 million, 48 percent, to $32.0 million for 2004 from $21.6 million for 2003. Exploration costs for 2004 consisted of $10.8 million for seismic and other geological and geophysical costs, $16.5 million for unsuccessful exploratory drilling and $4.7 million for impairment of unproved leaseholds. During 2003, our exploration costs included $10.0 million for seismic and other geological and geophysical costs, $7.3 million for unsuccessful exploratory drilling and $4.3 million for impairment of unproved leaseholds.

Exploration costs decreased $1.3 million, six percent, to $21.6 million for 2003 from $22.9 million for 2002. During 2002, our exploration costs included $5.0 million for seismic and other geological and geophysical costs, $13.9 million for unsuccessful exploratory drilling and $4.0 million for impairment of unproved leaseholds.

General and administrative expenses. General and administrative expenses increased $9.6 million, 20 percent, to $56.5 million for 2004 from $46.9 million for 2003. The increase is due primarily to higher employee bonus expenses and severance benefits for a former executive in 2004 with no corresponding amounts in 2003. As a result of these compensation-related expenses, our general and administrative expenses per BOE increased from $2.02 in 2003 to $2.30 in 2004.

General and administrative expenses increased $8.3 million, 22 percent, to $46.9 million for 2003 from $38.6 million for 2002. The increase is due primarily to Argentine asset taxes and cash bonuses in 2003 with no comparable amounts in 2002. These increases, along with a five percent decline in production from 2002 to 2003, increased our general and administrative expenses per BOE to $2.02 in 2003 from $1.57 in 2002.

Stock compensation. Stock compensation increased $2.3 million, 45 percent, to $7.6 million in 2004 from $5.3 million in 2003. In March 2004, we entered into a separation agreement with a former executive under which we extended the period in which he could exercise his outstanding vested stock options to the end of the term of the options. Under the terms of the non-vested stock award agreements with the former executive, all of the non-vested shares granted to him under these agreements became fully vested as of his termination date. As a result of these events, we recorded additional non-cash stock compensation expense of approximately $2.2 million in 2004. In June 2004, we recorded stock compensation expense of $1.1 million related to the vesting of certain performance-based non-vested stock grants. There were no comparable charges in 2003.

Stock compensation increased $4.4 million, 522 percent, to $5.3 million in 2003 from $0.9 million in 2002. Stock compensation expense relates primarily to non-vested stock awards. We granted approximately 1.2 million and 417,000 non-vested stock awards in 2003 and 2002, respectively. These awards generally vest over a one to three year period and the compensation expense is amortized over the vesting period. The 2003 grants included 563,000 non-vested stock awards that were issued in exchange for options to purchase 2.1 million shares of our common stock. Also, in 2003, we began expensing stock options on a prospective basis and recorded expense of $0.1 million in 2003 with no corresponding amount in 2002.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased $15.4 million, 18 percent, to $103.2 million for 2004 from $87.8 million for 2003. Our average oil and gas amortization rate per BOE increased to $4.08 for 2004 from $3.63 for 2003 due to increases in our finding costs during 2003 and 2004. A production increase of six percent on an equivalent barrel basis led to the increase in total depreciation, depletion and amortization during 2004.

Depreciation, depletion and amortization decreased $17.1 million, 16 percent, to $87.8 million for 2003 from $104.9 million for 2002. Our average oil and gas amortization rate per BOE decreased to $3.63 for 2003 from $4.09 for 2002. The decrease primarily resulted from the impact that substantially higher product prices in 2003 had in increasing proved reserves used to determine the amortization rate and, to a lesser extent, our mandated adoption of SFAS 143. Previously, we accrued an undiscounted estimate of future abandonment costs of wells and related facilities through our depreciation calculation in accordance with the provisions of Statement of Financial Accounting Standards No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*, ("SFAS 19") and industry practice. With the adoption of SFAS 143, we have now recorded a discounted fair value of the future retirement obligation as a liability with a corresponding amount capitalized as part of the related property's carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset based on proved developed reserves. The liability accretes over time with a charge to accretion expense, which was $6.0 million for 2003. As a result of the implementation of SFAS 143, we recorded a non-cash gain of $11.2 million ($7.1 million net of tax) as a cumulative effect of change in accounting principle.

Impairment of proved oil and gas properties. We recorded expense for the impairment of certain U.S. proved oil and gas properties of $6.0 million in 2004, $6.1 million in 2003 and $17.0 million in 2002. These impairments in all three years resulted from a downward revision of our estimate of those properties' proved oil and gas reserves based on production performance. See Note 1 to the accompanying consolidated financial statements for a discussion of our policy for recording impairments of proved oil and gas properties. Due to the volatility of oil and gas prices, it is possible that our assumptions regarding oil and gas prices may change in the future. If in the future price expectations are reduced or estimated proved reserves are revised downward, it is possible that additional significant impairment provisions for proved oil and gas properties would be required.

Other operating costs. Other operating costs decreased $3.8 million, 62 percent, to $2.3 million in 2004 from $6.1 million in 2003. This decrease is due to a $6.0 million gain recorded from a settlement of a certain contract claim that we had against a third party. Other operating costs were essentially unchanged from 2002 to 2003.

Interest expense. Interest expense decreased $18.0 million, 26 percent, to $51.8 million for 2004 from $69.8 million for 2003 due to a 12 percent reduction in our average debt outstanding and a 13 percent decrease in our average interest rate during 2004. During the first quarter of 2004, we advanced funds under our revolving credit facility to redeem the entire $150 million principal balance of our 9 3/4% senior subordinated notes due 2009. In December 2004, we used a portion of the proceeds from the sale of our Canadian operations to reduce all borrowings under our revolving credit facility. At December 31, 2004, our average interest rate on our then outstanding debt was 8.1 percent.

Interest expense decreased $7.5 million, 10 percent, to $69.8 million for 2003 from $77.3 million for 2002 due to a 21 percent reduction in our average debt outstanding.

Loss on early extinguishment of debt. In connection with the redemption of our senior subordinated notes during 2004, as discussed above, we were required to pay call premiums on the notes and expense certain associated deferred financing costs and discounts related to the notes, resulting in losses on early extinguishment of debt of $9.9 million ($6.0 million after tax) in 2004. This compares to losses on early extinguishment of debt of $6.9 million ($4.2 million after tax) in 2003 and $8.2 million ($5.0 million after tax) in 2002, as discussed below.

In 2003, we redeemed the remainder of our 9% senior subordinated notes and the entire balance of our 8 5/8% senior subordinated notes using advances under our revolving credit facility. As a result, we were required to expense the remaining associated deferred financing costs and discounts. This $3.0 million non-cash charge and a $3.9 million cash charge for the call premium on the redemption of these notes resulted in a charge of $6.9 million in 2003.

In 2002, in conjunction with the issuance of our 8 1/4% senior notes, we redeemed a portion of our 9% senior subordinated notes and entered into a new $300 million revolving credit facility. We were required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% senior subordinated notes, resulted in a charge of $8.2 million in 2002.

Gain or loss on disposition of assets. A net loss on disposition of assets of $1.2 million ($0.7 million net of tax) was reflected in 2003 related to sales of certain U.S. Mid-Continent gas properties. Total proceeds from these sales were $30.0 million. In 2002, we recorded a net gain on disposition of assets of $16.6 million ($10.1 million net of tax) primarily related to the sale of our heavy oil properties in the Santa Maria area of Southern California. The 2002 gain included the reversal of our accrual for future abandonment costs related to the sold properties.

Foreign currency exchange (gain) loss. We recorded foreign currency exchange gains of $0.8 million in 2004, foreign currency exchange losses of $6.7 million in 2003 and a foreign currency exchange gain of $0.3 million in 2002. These gains and losses are primarily related to our operations in Argentina. Foreign currency exchange gains and losses in other countries were not significant in either period.

During 2004, the Argentine peso was relatively unchanged against the U.S. dollar, with an exchange rate of 2.98 pesos to one U.S. dollar at December 31, 2004, compared to a rate of 2.94 pesos to one U.S. dollar at December 31, 2003. The Argentine peso strengthened significantly against the U.S. dollar during 2003, with an exchange rate of 2.94 pesos to one U.S. dollar at December 31, 2003, compared to a rate of 3.38 pesos to one U.S. dollar at December 31, 2002.

As discussed in Note 1 to our 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. During 2002, the peso declined in value, falling from a rate of 1.65 pesos to one U.S. dollar at January 11, 2002, to 3.38 pesos to one U.S. dollar at December 31, 2002. Included in "Foreign currency (gain) loss" for 2002 was a gain of $0.9 million related to the Argentine government-mandated negotiated settlement of U.S. dollar-denominated receivables and payables in existence at January 6, 2002.

Derivative losses. We recorded total derivative losses of $21.7 million during 2004 related to settlements and market value adjustments of derivative commodity instruments that did not qualify or ceased to qualify for hedge accounting, compared to derivative losses of $1.5 million during 2003 and $0.5 million in 2002. Beginning in September 2004 and continuing through year-end, the differential between the NYMEX index price for crude oil and West Coast and other U.S. crude oil postings widened. Although the NYMEX crude oil index prices increased, many crude oil postings under which we sell our oil did not increase at the same rate. This market fluctuation caused us to conclude that most of our crude oil hedges were no longer highly effective in achieving offsetting changes in the cash flows of the physical transactions. In accordance with SFAS 133, we discontinued hedge accounting for these contracts beginning in September and recorded the changes in the fair value of these contracts as a charge to "Derivative losses." The fair value of these contracts, which ceased to qualify for hedge accounting at December 31, 2004, was a liability of $14.2 million. As of March 1, 2005, the Company has determined that the correlation indicates that its existing oil price swap agreements will again be highly effective in achieving offsetting changes in the cash flows of the physical transactions and, accordingly, has redesignated all of the oil price swap contracts as cash flow hedges and will resume hedge accounting for these contracts as of March 1, 2005. Derivative losses in 2003 primarily relate to certain cash flow hedges for which the future physical transaction was no longer deemed probable as a result of the shut-in of certain producing oil wells in California due to the October 2003 fires.

Cumulative effect of change in accounting principle. We implemented SFAS 143 effective January 1, 2003. Previously, we accrued an undiscounted estimate of future abandonment costs of wells and related facilities through our depreciation calculation. With the implementation of SFAS 143, we now record a discounted fair value of the future retirement obligation as a liability with a corresponding amount capitalized as part of the related property's carrying amount at acquisition date of a producing property or at the completion of drilling. We amortize the discounted capitalized asset retirement cost to expense through our depreciation calculation over the estimated useful life of the asset. We accrete the liability over time with a charge to accretion expense. As a result of the implementation of SFAS 143, we recorded a cumulative effect of change in accounting principle of $7.1 million, net of taxes of $4.1 million, in the first quarter of 2003.

Effective January 1, 2002, we adopted the provisions of SFAS 142. SFAS 142 changed the accounting for goodwill from an amortization method to an impairment-only method. Our goodwill related to our Canadian operations which were sold in November 2004. We tested goodwill for impairment in conjunction with a transitional goodwill impairment test in 2002. As a result of the transitional impairment test, we recorded a $60.5 million charge as a cumulative effect of change in accounting principle retroactive to January 1, 2002, in accordance with the provisions of SFAS 142. Decreases in oil and gas price expectations from the May 2, 2001, acquisition of Genesis to January 1, 2002, and certain downward revisions recorded to our Canadian oil and gas reserves at December 31, 2001, were the primary factors that led to the goodwill impairment at January 1, 2002. The annual impairment tests as of December 31, 2003 and 2002, resulted in additional charges of $25.7 million and $76.4 million in 2003 and 2002, respectively, which are now reflected in losses from discontinued operations. Certain downward revisions recorded to our Canadian oil and gas reserves in the fourth quarters of 2002 and 2003 were the primary reason for the additional goodwill impairments. As of December 31, 2003, we had no remaining goodwill recorded on our balance sheet.

Cash Flows

Our primary sources of cash during 2004 were funds generated from operations and proceeds from the sale of our Canadian operations. The cash was primarily used to reduce long-term debt, fund capital expenditures and pay dividends, with the remainder increasing our cash position by $92.0 million. See below for additional discussion of our cash flows from operating activities.

	Years Ended December 31, 2004	Years Ended December 31, 2003	Change
	(in thousands)		
Cash provided (used) by:			
Operating activities - continuing operations	$ 337.6	$ 212.5	$ 125.1
Operating activities - discontinued operations	14.7	21.3	(6.6)
Investing activities - continuing operations	(105.6)	4.8	(110.4)
Investing activities - discontinued operations	7.8	(13.3)	21.1
Financing activities	(163.1)	(201.9)	38.8

Cash provided by continuing operations increased 59 percent to $337.6 million in 2004 versus $212.5 million in 2003 primarily as a result of significantly higher oil and gas prices and a six percent increase in production. The impact of higher prices and production was partially offset by higher operating costs. See "Results of Operations" and "Period to Period Comparisons" for further discussions. We did not see a significant difference between years in cash provided or used by changes in total working capital amounts. Cash provided by operating activities - discontinued operations for both years represents the cash provided from our discontinued Canadian operations and, in 2003, is partially offset by the payment of current taxes associated with the sale of our operations in Ecuador.

Cash provided or used by investing activities in 2004 and 2003 has been significantly impacted by our decision to reduce debt with proceeds from the sale of oil and gas properties. Investing activities in 2004 include $241.5 million for proceeds from the sale of our operations in Canada, net of cash sold. Investing activities in 2003 include $146.1 million for proceeds from the sales of our operations in Ecuador and certain properties in the U.S. Capital spending by continuing operations was $309.8 million, or 92 percent of cash provided by continuing operations, in 2004 and $144.8 million, or 68 percent of cash provided by continuing operations in 2003. We do not anticipate significant proceeds from property sales in 2005 and we have established our 2005 non-acquisition capital budget at $250 million, which is below our 2005 expected cash flows.

Cash used by financing activities in 2004 and 2003 reflects the results of our debt reduction program as we have redeemed our 9 3/4% senior subordinated notes due 2009 in 2004 and our 9% senior subordinated notes due 2005 and 8 5/8% senior subordinated notes due 2009 in 2003 and reduced our outstanding balance under our revolving credit facility to zero at December 31, 2004.

Capital Expenditures

During 2004, our total oil and gas capital expenditures were $365.2 million ($347.6 million related to continuing operations). In the U.S., our oil and gas capital expenditures totaled $180.4 million. Development activities accounted for $60.6 million of our U.S. capital expenditures with exploration activities contributing $34.6 million. We also spent $75.6 million on acquisitions of producing properties in the United States and $9.6 million on the acquisition of U.S. unproved acreage in 2004. During 2004, our international oil and gas capital expenditures totaled $184.8 million ($167.1 million on continuing operations). This continuing operations amount consists of acquisitions in Argentina of $34.9 million, development activities of $89.1 million in Argentina and $30.1 million in Yemen and exploration activities of $3.6 million in Yemen, $4.1 million in Argentina, $1.2 million in Bulgaria and $4.1 million in Italy.

As of December 31, 2004, we had total unproved oil and gas property costs of approximately $25.4 million consisting of undeveloped leasehold costs of $14.3 million and unevaluated exploratory drilling of $11.1 million. Approximately $14.6 million of the total unproved costs are associated with our drilling program in Yemen. Future exploration expense and earnings may be impacted to the extent our future exploration activities are unsuccessful in discovering commercial oil and gas reserves in sufficient quantities to recover our costs.

In December 2004, we acquired all of Exxon Mobil Corporation's interest in the Big Escambia Creek field and gas processing facility in Alabama. We paid $77.2 million, subject to post-closing adjustments. The 13 operated and two non-operated wells in this field are adjacent to our existing Flomaton and Fanny Church fields and plant and they produce condensate, gas and liquids of approximately 1,920 BOE per day.

In September 2004, we acquired 100 percent of an Argentine company whose principal asset is an operated producing concession which covers approximately 54,000 acres in the north flank of the San Jorge basin of Argentina. We paid total consideration of $34.9 million in cash. We estimate that the current net production attributable to the producing Bella Vista Oeste concession is 1.9 MBbls of oil and natural gas liquids per day from approximately 50 active producing wells. We believe that the properties contain significant workover, drilling and secondary production potential which we plan to pursue along with the implementation of operational efficiencies.

On May 2, 2001, we completed the acquisition of Genesis for total consideration of $617 million, including transaction costs and the assumption of the net indebtedness of Genesis at closing. In connection with our acquisition of Genesis, we financed the acquisition price of approximately $617 million with cash on hand of approximately $26 million and debt or assumed net obligations of approximately $591 million. The total acquisition amount includes cash paid at closing of $463 million, assumed debt of $88 million (which was immediately refinanced) and the assumption of a negative working capital position of approximately $66 million. The cash paid at closing in excess of the $26 million of cash on hand and the refinancing of the assumed debt were funded by advances from our revolving credit facility.

The timing of most of our capital expenditures is discretionary with no material long-term capital expenditure commitments. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures as circumstances warrant. We use internally-generated cash flows to fund our capital expenditures other than significant acquisitions. Our capital expenditure budget for 2005 is currently set at $250 million, exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. We are actively pursuing additional acquisitions of oil and gas properties. In addition to internally-generated cash flows and advances under our revolving credit facility, we 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 our desired acquisitions. Our recent capital expenditure history (including capital expenditures of discontinued operations) is as follows:

	Years Ended December 31,		
(In thousands)	2004	2003	2002
Acquisition of oil and gas reserves	$ 110,547	$ 463	$ -
Drilling	169,353	133,208	82,664
Acquisition of undeveloped acreage and seismic	24,418	21,537	19,592
Workovers and recompletions	57,129	22,592	24,673
Other	3,817	3,972	2,777
Oil and gas capital expenditures	365,264	181,772	129,706
Gathering system and plant projects	582	2,484	4,554
Total	$ 365,846	$ 184,256	$ 134,260

Capital Resources and Liquidity

Cash on hand, internally generated cash flows and the borrowing capacity under our revolving credit facility are our major sources of liquidity. We also have the ability to adjust our level of capital expenditures. We may use other sources of capital, including the issuance of additional debt securities or equity securities, to fund any major acquisitions we might secure in the future and to maintain our financial flexibility.

In the past, we have accessed the public markets to finance significant acquisitions and provide liquidity for our future activities. Since 1990, we have completed five public equity offerings as well as two public debt offerings and three Rule 144A private debt offerings, all of which have provided us with aggregate net proceeds of approximately $1.2 billion.

On May 30, 2001, we issued $200 million of our 7 7/8% Senior Subordinated Notes due 2011 (the "7 7/8% Notes"). The 7 7/8% Notes are redeemable at our option, in whole or in part, at any time on or after May 15, 2006. The 7 7/8% Notes mature on May 15, 2011, with interest payable semi-annually on May 15 and November 15 of each year. All of our net proceeds from the sale of the 7 7/8% Notes (approximately $199.9 million) were used to repay a portion of the existing indebtedness under our revolving credit facility.

On May 2, 2002, we issued, through a Rule 144A offering, $350 million of our 8 1/4% Senior Notes due 2012 (the "8 1/4% Notes"). All of the net proceeds were used to repay a portion of the outstanding balance under our revolving credit facility and to redeem $100 million of our outstanding 9% Senior Subordinated Notes due 2005 (the "9% Notes"). The 8 1/4% Notes are redeemable at our option, in whole or in part, at any time on or after May 1, 2007. In addition, prior to May 1, 2005, we may redeem up to 35 percent of the 8 1/4% Notes with the proceeds of certain underwritten public offerings of our common stock. The 8 1/4% Notes mature on May 1, 2012, with interest payable semi-annually on May 1 and November 1 of each year.

In conjunction with the offering of the 8 1/4% Notes, we entered into a new $300 million revolving credit facility (as amended, the "Bank Facility"), which was used to refinance our previously existing credit facility and to provide funds for ongoing operating and general corporate needs. We also redeemed a portion of the 9% Notes. As a result, we were required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% Notes, resulted in a one-time charge of approximately $8.2 million ($5.0 million net of tax) recorded in the second quarter of 2002.

During the first quarter of 2003, we advanced funds under the Bank Facility to redeem the remainder of the 9% Notes. As a result, we were required to expense certain associated deferred financing costs and discounts. This $0.7 million non-cash charge and a $0.7 million cash charge for the call premium on the redemption of the remaining 9% Notes in 2003 resulted in a one-time charge of approximately $1.4 million ($1.0 million net of tax) recorded in the first quarter of 2003.

In October 2003, we redeemed the entire $100 million principal balance of our 8 5/8% senior subordinated notes due 2009 with cash provided by advances under the Bank Facility. As a result, we were required to expense certain associated deferred financing costs and discounts. This $2.3 million non-cash charge and a $3.2 million cash charge for the call premium resulted in a one-time charge of approximately $5.5 million ($3.4 million net of tax) in the fourth quarter of 2003.

In February 2004, we redeemed the entire $150 million principal balance of our 9 3/4% senior subordinated notes due 2009 with cash provided by advances under the Bank Facility. As a result, we were required to expense certain associated deferred financing costs. The $2.6 million non-cash charge and a $7.3 million cash charge for the call premium resulted in a one-time charge of approximately $9.9 million ($6.0 million net of tax) that we recorded in the first quarter of 2004.

The Bank Facility consists of a senior secured credit facility maturing in May 2008 with availability governed by a borrowing base determination. Our availability under the Bank Facility is reduced by our outstanding letters of credit. The borrowing base (currently $325 million) is based on the banks' evaluation of our 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 $300 million. The next borrowing base redetermination will be in April 2005. The Bank Facility is secured by a first priority lien on our oil and gas properties constituting at least 80 percent of the present value of our U.S. proved reserves owned now or in the future. The Bank Facility will be guaranteed by any of our existing and future U.S. subsidiaries that grant a lien on oil and gas properties under the Bank Facility.

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 therein) or, at our option, at a fixed rate for up to six months based on the Eurodollar market rate ("LIBOR"). Our interest rate increments above the alternate base rate and LIBOR vary based on the level of outstanding senior secured debt to the borrowing base. In addition, we must pay a commitment fee ranging from 0.375 to 0.50 percent per annum (based on the ratio of the outstanding senior secured debt to the borrowing base) on the unused portion of the banks' commitment. As of February 28, 2005, we have unused availability under our revolving credit facility of $296.6 million (considering outstanding letters of credit of approximately $3.4 million).

The terms of the Bank Facility require the maintenance of a minimum current ratio (as defined therein) and a minimum tangible net worth (as defined therein). The indentures for our senior notes and our senior subordinated notes contain limitations on, among other things, additional indebtedness and liens, the payments of dividends and other distributions, certain investments and transfers or sales of assets.

The significant non-cash charges for impairments of our U.S. and Canadian oil and gas properties that we recorded in 2003 had no material adverse impact on the financial covenants under the Bank Facility or our existing bond indentures. Our current borrowing base under the Bank Facility is based primarily on our U.S. reserves.

The significant impairments related to our Canadian operations we recorded in 2002 and 2003 indicated that the expected cash flows from such operations were expected to be substantially reduced in the future. During 2004, we sold all of our Canadian operations for proceeds of approximately $274.7 million, a portion of which were used to eliminate all advances then outstanding under the Bank Facility. We believe that due to our substantial remaining assets, the impact of such Canadian impairments and the subsequent sale of our Canadian operations did not result in our inability to satisfy all of our debt and other obligations as they come due.

Our internally generated cash flows, results of operations and financing for our operations are dependent on oil and gas prices. Realized oil and gas prices for the year increased by 21 percent and 37 percent, respectively, as compared to 2003. For 2004, approximately 68 percent of our production on a BOE basis from continuing operations was oil. We believe that our cash flows and unused availability under the Bank Facility are sufficient to fund our planned capital expenditures for the foreseeable future. To the extent oil and gas prices decline, our earnings and cash flows from operations may be adversely impacted. Prolonged periods of substantially lower oil and gas prices could cause us to not be in compliance with maintenance covenants under our Bank Facility and could negatively affect our credit statistics and coverage ratios and thereby affect our liquidity.

Consistent with our stated goal of maintaining financial flexibility and optimizing our portfolio of assets, we announced in early 2002 plans to reduce debt by $200 million through a combination of asset sales and cash flows in excess of planned capital expenditures. We determined that the level of investment and time horizon required to continue the development of our interests in Ecuador and Trinidad were inconsistent with the timing of our desire to reduce leverage. These assets, along with our remaining heavy oil properties in the Santa Maria area of southern California, were identified for sale. Our heavy oil properties in the Santa Maria area of southern California were sold in June 2002 for $9.5 million in cash and a note receivable for $6 million, bearing monthly payments of $360,000, plus interest, with final maturity in June 2003. We received a cash payment as final settlement of this note in October 2002. Our interest in Trinidad was sold in July 2002 for $40 million in cash; our interest in Ecuador was sold in January 2003 for $137.4 million in cash. The closing of the sale of our interest in Ecuador, along with the sales of certain U.S. Mid-Continent gas properties and certain non-strategic oil and gas assets in Saskatchewan and West Central Alberta, Canada for a total of $57.9 million, allowed us to exceed our $200 million debt reduction goal. Subsequently, we sold our Canadian operations in November 2004 for $274.7 million in cash. Our debt, less cash on hand, at December 31, 2004, was $425.7 million, compared to approximately $1.0 billion at December 31, 2001.

Off Balance Sheet Arrangements and Contractual Obligations

We have no off balance sheet arrangements, as defined by SEC rules. A summary of our contractual obligations as of December 31, 2004, is as follows (in thousands):

	Payments Due By Year						
	Total	2005	2006	2007	2008	2009	Thereafter
Long-term debt (a)	$ 550,000	$ -	$ -	$ -	$ -	$ -	$ 550,000
Operating leases (b)	8,467	2,370	2,338	3,759	-	-	-
Firm transportation and compression agreements (b)	3,323	1,187	1,269	269	299	299	-
Argentina electric power agreement (b)	12,067	3,574	3,574	4,919	-	-	-
Purchase commitments	8,204	8,204	-	-	-	-	-
Yemen concession agreement (b)	6,415	338	338	338	338	338	4,725
	$ 588,476	$ 15,673	$ 7,519	$ 9,285	$ 637	$ 637	$ 554,725

(a) See Note 2 "Long-term Debt" to our consolidated financial statements included elsewhere in this Form 10-K.

(b) See Note 4 "Commitments and Contingencies" to our consolidated financial statements included elsewhere in this Form 10-K.

We have no capital leases. The table above does not include $3.6 million of letters of credit that have been issued by commercial banks on our behalf which, if funded, would become borrowings under our revolving credit facility. The $550 million of long-term debt shown in the table excludes approximately $51,000 of discounts, which are included in the amount shown on our December 31, 2004, balance sheet. The table above also does not include payments that we have agreed to make in the Argentine province of Santa Cruz to improve employment rates, social development and education resources. These payments are estimated to be 3.8 million pesos ($1.3 million) for 2005, 3.8 million pesos ($1.3 million) for 2006 and 1.7 million pesos ($0.6 million) for 2007.

Material contractual cash obligations for which the ultimate settlement amounts are not fixed and determinable include derivative contracts that are sensitive to future changes in commodity prices. See "Item 7A. Quantitative and Qualitative Disclosure about Market Risk - Commodity Price Risk" included elsewhere in this Form 10-K.

Inflation

During 2004, the Argentine inflation rate amounted to 6.1 percent for the year. In recent years, inflation outside of Argentina has not had a significant impact on our operations or financial condition and is not currently expected to have a significant impact on future periods.

Income Taxes

We recorded a current provision for income taxes from continuing operations of $57.9 million, $40.1 million and $16.0 million for 2004, 2003 and 2002, 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 our foreign subsidiaries are subject to foreign income taxes. At December 31, 2004, unremitted earnings of subsidiaries outside of the U.S. were approximately $425 million, on which no U.S. taxes had been provided as it is our intention, generally, to invest such earnings permanently or to repatriate the earnings only when possible to do so at minimal additional tax cost. We have paid or accrued foreign income taxes of approximately $230 million related to these earnings which may be available as a credit against U.S. federal income taxes on such income, if distributed. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed because the amount of foreign taxes eligible for credit against U.S. federal income taxes on any such distribution will be determined based on facts and circumstances at the time of any actual distribution. We expect that foreign income taxes will constitute a substantial portion of our overall tax burden in the foreseeable future.

The American Jobs Creation Act of 2004 (the "Jobs Act") introduced a special one-time dividends-received deduction on the repatriation of certain foreign earnings to the U.S., provided certain conditions are met. If certain conditions are met, a 5.25 percent effective income tax rate would apply to eligible repatriations of certain foreign earnings. We are currently evaluating these provisions under the Jobs Act and we are also awaiting interpretive guidance relating to these regulations from either Congress or the Treasury Department. At the current date, we have not determined that we will repatriate any unremitted foreign earnings under the special one-time repatriation provisions of the Jobs Act. However, we continue to evaluate the special one-time repatriation provisions of the Jobs Act and that evaluation could result in us repatriating certain unremitted foreign earnings. The amount of unremitted foreign earnings that we are evaluating for repatriation, including projected 2005 earnings, ranges from zero to $500 million. We expect to complete our evaluation of the amount of repatriation, if any, during 2005. If we were to repatriate certain unremitted foreign earnings under the special one-time repatriation provisions of the Jobs Act in the range noted in the preceding sentence, the income tax effects of such repatriation could range from zero to approximately $26 million.

We have various state net operating loss 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. We have a Bolivian income tax NOL carryforward of approximately $39 million that does not expire. We have also incurred approximately $80 million related to our Yemen operations that we expect to recover under the cost recovery provisions of our production sharing agreement with the government of Yemen. These provisions allow us to annually offset a portion of our revenues that would otherwise be taxable with costs we previously incurred in Yemen until such costs have been fully recovered. We expect to recover this amount over the next five years.

Changes in our income tax provision (benefit) are a function of our consolidated effective tax rate and our pre-tax income (loss). The increase in our income tax expense for 2004 as compared to 2003 is primarily due to higher pre-tax earnings resulting from higher product prices and production. Our overall effective tax rate on continuing operations was 35.7 percent and 41.3 percent for 2004 and 2003, respectively.

As part of our results from discontinued operations for 2004, we recorded a U.S. income tax benefit of $30.7 million related to prior year taxes to be refunded as a result of our intent to carry back a portion of the capital loss for tax purposes generated by the disposal of our Canadian operations, bringing the 2004 effective tax rate on discontinued operations to 14.8 percent, compared to 24.4 percent for 2003, which primarily related to the sale of our Ecuador subsidiary. As part of our results from discontinued operations for 2003, we recorded additional U.S. income taxes of $19.4 million related to the repatriation of previously untaxed foreign earnings as a result of the sale of our Ecuador subsidiary in January 2003.

Critical Accounting Policies and Estimates

Management's discussion and analysis of our financial condition and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). GAAP represents a comprehensive set of accounting and disclosure rules and requirements, the application of which requires management judgments and estimates including, in certain circumstances, choices between acceptable GAAP alternatives. 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. We base our 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 our consolidated financial statements included elsewhere in this Form 10-K, contains a comprehensive summary of our significant accounting policies. The following is a discussion of our most critical accounting policies, judgments and uncertainties that are inherent in our application of GAAP:

Accounting for Oil and Gas Properties. Under the successful efforts method of accounting, we capitalize all costs related to property acquisitions and successful exploratory wells, all development costs and the costs of support equipment and facilities. Certain costs of exploratory wells are capitalized pending determination that proved reserves have been found. Such determination is dependent upon the results of planned additional wells and the cost of required capital expenditures to produce the reserves found. All costs related to unsuccessful exploratory wells are expensed when we determine that such wells have not found proved reserves; other exploration costs, including geological and geophysical costs, are expensed as incurred. We recognize gains or losses on the sale of properties on a field basis.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze, and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. Wells may be completed that are assumed to be productive and actually deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. The evaluation of oil and gas leasehold acquisition costs requires management's judgment to estimate the fair value of exploratory costs related to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

The successful efforts method of accounting can have a significant impact on the operational results reported when we enter a new exploratory area in hopes of finding oil and gas reserves. Seismic costs can be substantial which will result in additional exploration expenses when incurred. The initial exploratory wells may be unsuccessful and the associated costs will then be expensed as dry hole costs and any associated leasehold costs may be impaired.

Development Seismic Costs. We expense all exploration seismic costs as incurred. Delineation seismic costs incurred to select development locations within a productive oil and gas field are typically treated as development costs and capitalized. Judgment is required to determine when the seismic programs are not within proved areas and therefore would be charged to expense as exploratory costs.

We capitalized approximately $2.0 million, $1.9 million and $1.7 million of 3-D seismic costs incurred in our development activities in the years ended December 31, 2004, 2003 and 2002, respectively. As of December 31, 2004, a total of approximately $22.0 million (net of accumulated amortization of approximately $6.4 million) of development seismic costs are included in net property, plant and equipment in our balance sheet.

In connection with a routine review of our 2003 Form 10-K, the SEC has evaluated the appropriateness of our accounting policy for development seismic costs. On March 11, 2005, the SEC provided us with guidance regarding the application of this accounting policy. Based on a preliminary review of the impact this guidance may have on previously capitalized costs, we believe that the impact of any potential adjustment would not be material to our consolidated financial statements for the years ended December 31, 2004, 2003 and 2002.

Exploration Drilling Costs. Costs of drilling exploratory wells are capitalized as part of our unproved costs, pending management's determination of whether the wells have found proved reserves. Management makes this determination as soon as possible after completion of drilling considering the guidance provided in SFAS 19. SFAS 19 provides that such costs should not be carried as an asset for more than one year following completion of drilling, unless the well has found oil and gas reserves in an area requiring a major capital expenditure before production could begin. In that case, the costs of such exploration well continue to be carried as an asset pending determination of whether proved reserves have been found only as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and drilling of the additional exploratory wells is under way or firmly planned for the near future. If both those conditions are not met, the well costs are charged to expense. Management performs this evaluation on a quarterly basis. See Note 1 to the consolidated financial statements for additional information.

The Financial Accounting Standards Board ("FASB") has recently issued Proposed FASB Staff Position No 19-A, *Accounting for Suspended Well Costs* ("FSP 19-A"). If adopted as proposed, FSP 19-A will amend SFAS 19 to provide that in those situations where exploration drilling has been completed and oil and gas reserves have been found, but such reserves cannot be classified as proved when drilling is complete, the drilling costs may be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either of the criteria is not met, the well is assumed to be impaired and the costs charged to expense. Any well which has not found reserves is charged to expense. Management believes that no adjustment would have been required as of the beginning of and for each of the three years in the period ended December 31, 2004, from the application of the proposed FSP 19-A.

Proved reserve estimates. Estimates of our proved reserves included in our consolidated financial statements and elsewhere in this Form 10-K are prepared in accordance with guidelines established by GAAP and by the SEC. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. 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.

Our proved reserve information is based primarily on estimates prepared by our independent petroleum consultants. As of December 31, 2004, fields comprising approximately four percent of our total proved reserves were estimated by us. 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 our 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 we record 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, or from volume revisions resulting from actual production rates, drilling results in nearby areas or other factors. In addition, the decline in proved reserve estimates may impact the outcome of our assessment of our oil and gas producing properties for impairment.

Impairment of proved oil and gas properties. We review our 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 our expectations of future oil and gas prices and costs, consistent with methods used for acquisition evaluations. Oil and gas reserve estimates may change in future periods and oil and gas prices are historically volatile. Events may arise that will require us to record an impairment of our oil and gas properties and there can be no assurance that such impairments will not be required in the future.

Impairment of unproved oil and gas properties. Unproved leasehold costs and exploratory drilling in progress are capitalized and are reviewed periodically for impairment. Costs related to impaired prospects or unsuccessful exploratory drilling are charged to expense. Our assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such leaseholds impacts the amount and timing of impairment provisions. 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. As of December 31, 2004, we had total unproved oil and gas property costs of approximately $25.4 million consisting of undeveloped leasehold costs of $14.3 million and unevaluated exploratory drilling costs of $11.1 million. Approximately $14.6 million of the total unevaluated costs are associated with our drilling program in Yemen.

Estimates of future dismantlement, restoration, and abandonment costs. Through December 31, 2002, we had accrued future abandonment costs of wells and related facilities through our depreciation calculation in accordance with the provisions of SFAS 19 and industry practice. The accounting for future development and abandonment costs changed on January 1, 2003, with the adoption of SFAS 143. Under both methods of accounting, the accrual is based on estimates of these costs for each of our properties based upon the type of production structure, reservoir characteristics, depth of the reservoir, market demand for equipment, currently available procedures and consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make estimates and judgments that are subject to future revisions based on numerous factors, including changing technology, the political and regulatory environment and, beginning in 2003, estimates as to the proper discount rate to use and timing of abandonment.

Accounting for Derivative Financial Instruments. We periodically use derivative financial instruments as hedges to reduce the impact of oil and natural gas price fluctuations and we generally attempt to qualify such derivatives as hedges for accounting purposes. We account for our derivative activities under the provisions of SFAS 133, which requires us to record the fair value of our derivative financial instruments as either an asset or liability on our balance sheet. We utilize market-based quotes from our counterparties to value our open positions. Future market price volatility for oil and gas could result in significant changes to the amounts recorded on our balance sheet.

We must formally designate each cash flow hedge as such at its inception, documenting the nature of the risk being hedged, the specific hedged item and its volume, the hedging instrument and our basis for selecting that instrument, and the methodologies we will use to assess and measure the hedge's effectiveness or ineffectiveness. To the extent that the derivative financial instruments qualify as effective cash flow hedges, we record any gains or losses on the open position in other comprehensive income. We record the results of settled oil or gas hedges as an adjustment to oil and gas sales in the period that the hedged forecasted transaction is recorded. Both at its inception and on an ongoing basis, we must use judgment to assess whether the hedging instrument has been and will continue to be highly effective in offsetting the changes in cash flows of the hedged transaction. If a derivative financial instrument does not qualify or ceases to qualify as an effective cash flow hedge, we record all settlements and changes in its fair value currently in our results of operations as non-operating income or expense. Any amounts previously recorded in accumulated other comprehensive income (loss) will then be recognized into earnings in the period that the forecasted transaction affects earnings.

SFAS 133 also requires us to continually assess whether occurrence of the forecasted transaction is probable. If we determine that the forecasted transaction in a cash flow hedge is no longer probable, we must discontinue hedge accounting for that derivative financial instrument, reclassify any amounts in other comprehensive income into our results of operations and record any changes in that instrument's fair value in our results of operations from that point forward unless it is redesignated in a new qualifying hedge relationship.

Income taxes. We provide deferred income taxes on transactions which are recognized in different periods for financial and tax reporting purposes. We have not recognized a U.S. deferred tax liability related to the unremitted earnings of any of our foreign subsidiaries as it is our intention, generally, to reinvest such earnings permanently. Management periodically assesses the need to utilize these unremitted earnings to finance our operations. This assessment is based on cash flow projections that are the result of estimates of future production, commodity pricing and expenditures by tax jurisdiction for our operations. Such estimates are inherently imprecise since many assumptions utilized in the cash flow projections are subject to revision in the future.

We have also recorded deferred tax assets related to operating loss and tax credit carryforwards. We periodically assess the probability of recovery of recorded deferred tax assets based on our assessment of future earnings outlooks by tax jurisdiction and record valuation allowances when this assessment results in a determination that recoverability is not likely. Such estimates and determinations are inherently imprecise because many assumptions are utilized in the assessments that may prove to be incorrect in the future.

Assessments of functional currencies. All of our subsidiaries use the U.S. dollar as their functional currency. Prior to the sale of our Canadian operations in November 2004, our Canadian subsidiary used the Canadian dollar as its functional currency. Management determines the functional currencies of our 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 financial statements of our operations in Argentina reflect management's assumptions regarding uncertainties unique to Argentina's current economic situation. See Note 1 to our 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. Argentina's economic and political situation evolves continuously and the Argentine government has adopted numerous decrees, is considering implementing various alternatives and may enact future regulations or policies that may materially impact, among other items, (i) the realized prices we receive for oil and gas we produce and sell; (ii) the timing and amount of repatriations of cash to the U.S.; (iii) the amount of permitted export sales; (iv) the Argentine banking system; (v) our asset valuations; and (vi) 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.

Changes in Accounting Principles

On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, *Business Combinations* ("SFAS 141"), and SFAS 142. SFAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. Under SFAS 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.

We adopted SFAS 141 and SFAS 142 effective January 1, 2002, resulting in the elimination of goodwill amortization from statements of operations in future periods. As discussed in Note 7 to our consolidated financial statements included elsewhere in this Form 10-K, we recorded an impairment charge of $60.5 million related to the goodwill of our Canadian operations as a cumulative effect of a change in accounting principle in our statement of operations.

On January 1, 2002, we adopted the provisions of SFAS 144. SFAS 144 creates 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 adoption of SFAS 144 did not have a material impact on our financial position or results of operations.

On April 30, 2002, the FASB issued Statement of Financial Accounting Standards No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections* ("SFAS 145"). SFAS 145 updates, clarifies and simplifies existing accounting pronouncements. Among other items, it rescinds previous accounting rules which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. We have adopted the provisions of SFAS 145 in 2002 and, accordingly, have classified losses on the early extinguishment of debt of $9.9 million ($6.0 million net of tax) in 2004, $6.9 million ($4.2 million net of tax) in 2003 and $8.2 million ($5.0 million net of tax) in 2002 (see Note 2 to our consolidated financial statements included elsewhere in this Form 10-K) as non-operating expenses in our statements of operations. The adoption of SFAS 145 did not have any other material impact on our financial position or results of operations.

In August 2001, the FASB issued SFAS 143. We were required to adopt this new standard beginning January 1, 2003. Through December 31, 2002, we accrued future abandonment costs of wells and related facilities through our depreciation calculation and included the cumulative accrual in accumulated depreciation in accordance with the provisions of SFAS 19 and industry practice. At December 31, 2002, approximately $54.6 million of accrued future abandonment costs were included in our accumulated depreciation. The new standard requires that we record the discounted fair value of the retirement obligation as a liability at the time a well is drilled or acquired. The asset retirement obligations consist primarily of costs associated with the plugging and abandonment of oil and gas wells, site reclamation and facilities dismantlement. However, future abandonment liabilities are also recorded for other assets such as pipelines, processing plants and compressors. A corresponding amount is capitalized as part of the related property's carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset based on proved reserves. The liability accretes over time with a charge to accretion expense. We adopted the new standard effective January 1, 2003, and recorded an increase in property, plant and equipment of approximately $50.3 million, a decrease in accumulated depreciation, depletion and amortization of approximately $43.9 million, an increase in current asset retirement liabilities of approximately $4.5 million, an increase in long-term asset retirement liabilities of approximately $78.5 million, a $4.1 million increase in deferred income tax liabilities and a gain as a result of the cumulative effect of change in accounting principle, net of tax, of approximately $7.1 million.

On July 30, 2002, the FASB issued Statement of Financial Accounting Standards No. 146, *Accounting for Costs Associated with Exit or Disposal Activities.* The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred rather than at the date of a commitment to an exit or disposal plan. The provisions of this statement are to be applied prospectively to exit or disposal activities initiated after December 31, 2002. The adoption of this standard had no impact on our financial position or results of operations.

On December 31, 2002, the FASB issued Statement of Financial Accounting Standards No. 148, *Accounting for Stock-Based Compensation - Transition and Disclosure* ("SFAS 148"). SFAS 148 amends Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* ("SFAS 123"), to provide alternative methods of transition to SFAS 123's fair value method of accounting for stock-based employee compensation. SFAS 148 also amends the disclosure provisions of SFAS 123 and APB Opinion No. 28, *Interim Financial Reporting,* to require disclosure in the summary of significant accounting policies of the effects of an entity's accounting policy with respect to stock-based employee compensation on reported net income and earnings per share in annual and interim financial statements. We adopted the disclosure provision of SFAS 148 in our consolidated financial statements included elsewhere in this Form 10-K as of December 31, 2002. Effective January 1, 2003, we adopted the fair value recognition provisions of SFAS 123. We adopted these provisions prospectively to all employee and director awards granted, modified or settled after January 1, 2003. The impact of adopting this standard was not significant to our results of operations.

In January 2003, the FASB issued Interpretation No. 46, *Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51* and revised this interpretation in December 2003 ("FIN 46"). FIN 46 requires the consolidation of variable interest entities by their primary beneficiary if the variable interest entities do not effectively disperse risks among the parties involved. Previously, entities were generally consolidated by an enterprise when it had a controlling financial interest through ownership of a majority of voting interest in the entity. The adoption of FIN 46 had no impact on our financial position or results of operations.

On April 30, 2003, the FASB issued Statement of Financial Accounting Standards No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* ("SFAS 149"). SFAS 149 is intended to result in more consistent reporting of contracts as either freestanding derivative instruments subject to SFAS 133 in its entirety, or as hybrid instruments with debt host contracts and embedded derivative features. SFAS 149 was effective for contracts entered into or modified after June 30, 2003, and hedging relationships designated after June 30, 2003. The adoption of SFAS 149 had no impact on our financial position or results of operations.

On May 15, 2003, the FASB issued Statement of Financial Accounting Standards No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* ("SFAS 150"). SFAS 150 establishes standards for classifying and measuring as liabilities certain financial instruments that embody obligations of the issuer and have characteristics of both liabilities and equity. SFAS 150 must be applied immediately to instruments entered into or modified after May 31, 2003, and to all other instruments that exist as of the beginning of the first interim financial reporting period beginning after June 15, 2003. Early adoption of SFAS 150 was not permitted. The adoption of SFAS 150 had no impact on our financial position or results of operations.

On December 16, 2004, the FASB issued Statement of Financial Accounting Standards No. 153, *Exchanges of Nonmonetary Assets - An Amendment of APB Opinion No. 29* ("SFAS 153"). SFAS 153 amends APB Opinion No. 29 ("APB 29"), *Accounting for Monetary Transactions*, that was issued in 1973. The amendments are based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. Further, the amendments eliminate the narrow exception for nonmonetary exchanges of similar productive assets and replace it with a broader exception for exchanges of nonmonetary assets that do not have "commercial substance." Previously, APB 29 required that the accounting for an exchange of a productive asset for a similar productive asset or an equivalent interest in the same or similar productive asset should be based on the recorded amount of the asset relinquished. The provisions in SFAS 153 are effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Companies must apply the standard prospectively. We do not believe the adoption of SFAS 153 will have a significant impact on our financial position or results of operations.

The FASB has issued Statement of Financial Accounting Standards No. 123 (Revised 2004), *Share-Based Payment* ("SFAS 123R"). SFAS 123R requires that the compensation cost relating to share-based payment transactions be recognized in the financial statements. That cost will be measured based on the fair value of the equity or liability instruments issued. We will be required to apply SFAS 123R as of the first interim reporting period that begins after June 15, 2005. We are presently evaluating the impact of SFAS 123R but we do not believe the adoption of SFAS 123R will have a significant impact on our financial position or results of operations.

The FASB has issued FASB Staff Position ("FSP") 109-1 and FSP 109-2 that provide accounting guidance on how companies should account for the effects of the American Jobs Creation Act of 2004 that was signed into law on October 22, 2004. The result of this legislation could affect how companies report their deferred income tax balances. The guidance in these FSP statements is effective December 21, 2004. In FSP 109-1, the FASB concludes that the tax relief (special tax deduction for domestic manufacturing) from this legislation should be accounted for as a "special deduction" instead of a tax rate reduction. We are evaluating the impact of FSP 109-1. FSP 109-2 gives a company additional time to evaluate the effects of the legislation on any plan for reinvestment or repatriation of foreign earnings for purposes of applying Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes.*

The FASB issued FSP FAS 141-1 and FAS 142-1 as a result of the March 17-18, 2004, Emerging Issues Task Force ("EITF") meeting, after the EITF reached a consensus on EITF Issue No. 04-2, "Whether Mineral Rights Are Tangible or Intangible Assets," and concluded that mineral rights, as defined in the issue, are tangible assets. There was an inconsistency between this consensus and the characterization of mineral rights as intangible assets in SFAS 141 and SFAS 142. Accordingly, this FSP amended SFAS 141 and SFAS 142 in order to address that inconsistency. The guidance in this FSP was applicable to the first reporting period beginning after April 29, 2004. The adoption of this FSP had no impact on the Company's financial position.

On occasion, we utilize buy/sell arrangements with third parties to enhance the value of our oil or gas production. These agreements involve the sale of oil or gas to a third party at one location and the re-purchase of the same volume of oil or gas at another location from the same third party. We then sell the oil or gas to another company at a negotiated price. We recognize in the financial statements only the ultimate sale of oil or gas as revenue at the net realized price, adjusted for any costs incurred in the buy/sell arrangement. The EITF is considering buy/sell arrangements and related matters in EITF Issue 04-13, including how buy/sell arrangements should be reported in the statements of operations. We believe that the effect of our historical buy/sell arrangements has not been significant and do not expect the resolution of EITF Issue 04-13 to have a significant effect on our financial position or results of operations.

Foreign Operations

For information on our 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 Disclosure About Market Risk.

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

Commodity Price Risk

We produce, purchase and sell crude oil, natural gas, condensate, natural gas liquids and sulfur. As a result, our 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 - Future Period Hedges" for a discussion of the impact of commodity price changes based on 2004 production levels. We have previously entered into oil and gas derivative transactions and we intend to continue to consider various derivative transactions to realize commodity prices which we consider favorable.

During 2002, we participated in oil price swap agreements covering 4.9 MMBbls of 2002 oil production at a weighted average NYMEX reference price of $25.16 per Bbl and gas price swap agreements covering 11.3 million MMBtu of 2002 gas production. The U.S. portion of the gas price swap agreements (5.2 million MMBtu) was at a NYMEX reference price of $2.72 per MMBtu. The Canadian portion of the gas price swap agreements (6.1 million MMBtu) was at the AECO gas price index reference price of 3.67 Canadian dollars per MMBtu and was settled in Canadian dollars. Additionally, we entered into gas price collar arrangements for 2.2 million MMBtu of our U.S. gas production in 2002 with floor NYMEX reference prices of $3.50 per MMBtu and cap NYMEX reference prices ranging from $4.00 to $5.10 per MMBtu. In conjunction with each of the 2002 U.S. gas price swap agreements and gas price collar agreements, we entered into basis swap agreements covering identical periods of time and volumes. These basis swaps established a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials we have received.

At December 31, 2002, we had entered into oil price swap agreements for a total of 3.0 MMBbls of 2003 oil production and gas price swap agreements for a total of 20.1 million MMBtu of 2003 gas production. Additionally, we had entered into basis swap agreements for approximately 8.4 million MMBtu of our 2003 U.S. gas production covered by the gas price swap agreements. At December 31, 2002, we would have been required to pay approximately $17.1 million to terminate our swap agreements then in place.

During 2003, we participated in oil price swap agreements covering 4.9 MMBbls of 2003 oil production and gas price swap agreements covering 20.1 million MMBtu of 2003 gas production. The U.S. portion of the oil price swap agreements (4.7 MMBbls) was at a weighted average NYMEX reference price of $26.79 per Bbl. The Canadian portion of the oil price swap agreements (0.2 MMBbls) was at a weighted average NYMEX reference price of 43.19 Canadian dollars per Bbl and was settled in Canadian dollars. The U.S. portion of the gas price swap agreements (11.0 million MMBtu) was at a weighted average NYMEX reference price of $4.00 per MMBtu. The Canadian portion of the gas price swap agreements (9.1 million MMBtu) was at a weighted average NYMEX reference price of 6.63 Canadian dollars per MMBtu and was settled in Canadian dollars. Additionally, we entered into basis swap agreements for approximately 8.4 million MMBtu of our 2003 U.S. gas production covered by the gas price swap agreements. These basis swaps established a differential between the NYMEX reference price and the various delivery points at levels that were comparable to the historical differentials we have received.

At December 31, 2003, we had entered into oil price swap agreements for a total of 5.0 MMBbls of 2004 and 2005 oil production. At that date, we would have been required to pay approximately $7.9 million to terminate our swap agreements then in place.

During 2004, we participated in oil price swap agreements covering 5.6 MMBbls of 2004 oil production and at a weighted average NYMEX reference price of $30.10 per Bbl and gas price swap agreements covering 21.8 million MMBtu of 2004 gas production at a weighted average NYMEX reference price of $5.92 per MMBtu. In conjunction with each of the 2004 U.S. gas price swap agreements, we entered into basis swap agreements covering identical periods of time and volumes. These basis swaps established a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials we have received.

At December 31, 2004, we had entered into oil price swap agreements for a total of 7.2 MMBbls of 2005, 2006 and 2007 oil production, gas price swap agreements for a total of 6.6 million MMBtu of 2005, 2006 and 2007 gas production at a weighted average NYMEX reference price of $6.31 per MMBtu, and gas price collar agreements for a total of 11.0 million MMBtu of 2005 gas production with NYMEX floor reference prices of $6.00 per MMBtu and NYMEX cap reference prices ranging from $6.80 to $9.21 per MMBtu. Additionally, we have entered into basis swap agreements for volumes and periods of time that coincide with each of the gas price swap agreements and gas price collar agreements for 2005, 2006 and 2007. At December 31, 2004, we would have been required to pay approximately $34.4 million to terminate our swap and collar agreements then in place.

The following table reflects the barrels covered by oil price swap agreements and the corresponding weighted average NYMEX reference prices by quarter:

Quarter Ending	Bbls	NYMEX Reference Price Per Bbl
March 31, 2005	1,242,000	$ 37.77
June 30, 2005	1,255,800	36.49
September 30, 2005	1,269,600	35.57
December 31, 2005	1,269,600	34.88
March 31, 2006	427,500	37.39
June 30, 2006	432,250	36.80
September 30, 2006	437,000	36.32
December 31, 2006	437,000	35.93
March 31, 2007	189,000	34.26
June 30, 2007	63,700	39.66
September 30, 2007	64,400	39.38
December 31, 2007	64,400	39.10

The following table reflects the MMBtu covered by gas price swap agreements and the corresponding weighted average NYMEX reference prices:

Quarter Ending	MMBtu	NYMEX Reference Price Per MMBtu
March 31, 2005	1,161,000	$ 6.65
June 30, 2005	1,173,900	6.15
September 30, 2005	1,186,800	6.17
December 31, 2005	1,186,800	6.37
March 31, 2006	243,000	6.47
June 30, 2006	245,700	6.47
September 30, 2006	248,400	6.47
December 31, 2006	248,400	6.47
March 31, 2007	225,000	6.00
June 30, 2007	227,500	6.00
September 30, 2007	230,000	6.00
December 31, 2007	230,000	6.00

The following table reflects the MMBtu covered by gas price collar agreements and the corresponding NYMEX floor and cap reference prices:

MMBtu For 2005	NYMEX Floor Reference Price Per MMBtu	NYMEX Cap Reference Price Per MMBtu
1,825,000	$ 6.00	$ 6.80
3,650,000	6.00	8.02
1,825,000	6.00	8.73
3,650,000	6.00	9.21

The counterparties to our current hedging agreements are commercial or investment banks. We continue to monitor oil and gas prices and we may enter into additional oil and gas derivative transactions in the future.

Interest Rate Risk

Our interest rate risk exposure results primarily from short-term rates, mainly LIBOR-based on borrowings from our commercial banks. To reduce the impact of fluctuations in interest rates, we have historically maintained a portion of our total debt portfolio in fixed-rate debt. At December 31, 2004, all of our outstanding debt was at fixed rates. However, we expect that this relationship will not continue and that a portion of our debt in future periods will be at variable rates. In the past, we have not entered into financial instruments such as interest rate swaps or interest rate lock agreements. However, we may consider these instruments to manage our portfolio mix between fixed and floating rate debt and to mitigate the impact of changes in interest rates based on our assessment of future interest rates, volatility of the yield curve and our ability to access the capital markets in a timely manner.

Because we had no outstanding borrowings under variable-rate debt instruments as of December 31, 2004, a change in the average interest rate of 100 basis points would result in no change in our net income (loss) and cash flows before income taxes.

The following table provides information about our long-term debt, principal payments and weighted-average interest rates by expected maturity dates as of December 31, 2004:

	2005	2006	2007	2008	2009	There-after	Total	Fair Value at 12/31/04
Long-term Debt:								
Fixed-rate (in thousands)	-	-	-	-	-	$550,000	$550,000	$598,875
Average interest rate	-	-	-	-	-	8.1%	8.1%	-
Variable-rate (in thousands) . .	-	-	-	-	-	-	-	-
Average interest rate	-	-	-	-	-	-	-	-

Foreign Currency and Operations Risk

International investments represent, and are expected to continue to represent, a significant portion of our total assets. We currently have international operations in Argentina, Bolivia, Yemen and Bulgaria. For 2004, our operations in Argentina accounted for approximately 41 percent of our revenues from continuing operations and 38 percent of our total assets. During 2004, our operations in Argentina represented our only foreign operation accounting for more than 10 percent of our revenues from continuing operations or total assets. We continue to identify and evaluate international opportunities, but we currently have no binding agreements or commitments to make any material international investment. As a result of such significant foreign operations, our 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.

On September 24, 2004, we entered into a forward sale of C$340 million related to the proceeds that we expected to receive at the closing of the sale of our Canadian operations. We received $266.1 million and we accounted for this transaction as a cash flow hedge. Other than this hedge, we have historically not used derivatives or other financial instruments to hedge the risk associated with the movement in foreign currencies. However, we evaluate currency fluctuations and we will consider the use of derivative financial instruments or employment of other investment alternatives if we believe cash flows or investment returns so warrant.

Our international operations may be adversely affected by political and economic instability, changes in the legal and regulatory environment and other factors. For example:

- local political and economic developments, as well as labor unrest, could restrict or increase the cost of our foreign operations;
- exchange controls and currency fluctuations could result in financial losses;
- royalty and tax increases and retroactive tax claims could increase costs of our foreign operations;
- expropriation of our property could result in loss of revenue, property and equipment;
- civil uprisings, riots, terrorist attacks and wars could make it impractical to continue operations, adversely affect both budgets and schedules and expose us to losses;
- import and export regulations and other foreign laws or policies could result in loss of revenues;
- repatriation levels for export revenues could restrict the availability of cash to fund operations outside a particular foreign country; and
- laws and policies of the U.S. affecting foreign trade, taxation and investment could restrict our ability to fund foreign operations or may make foreign operations more costly.

We do not currently maintain political risk insurance. However, we will consider obtaining such coverage in the future if we deem conditions so warrant.

Argentina. As a result of more than three years of economic instability and substantial withdrawals from the banking system, in early December 2001, the Argentine government, under President Fernando de la Rua, instituted restrictions that prohibit certain foreign money transfers without Central Bank approval and limit cash withdrawals from bank accounts to personal transactions in small amounts, with certain limited exceptions. In late December 2001, as a result of political riots and upheaval in response to the banking restrictions, Fernando de la Rua was removed as president and his successor, Adolfo Rodriguez Saa, immediately announced default on Argentina's $140 billion sovereign debt.

In early January 2002, congress conferred power to Eduardo Duhalde, who enacted temporary measures intended to achieve economic stability and avoid default on multilateral debts. On January 6, 2002, the Argentine government abolished its convertibility law that required an exchange of one peso to one U.S. dollar. The exchange rate at December 31, 2004, was 2.98 pesos to one U.S. dollar. The devaluation of the peso reduced our gas revenues and peso-denominated costs. Our oil revenues remain valued on a U.S. dollar basis.

Monetary assets and liabilities denominated in pesos at December 31, 2004, were as follows (in thousands):

	Peso Balance	U.S. Dollar Equivalent
Current assets	33,337	$ 11,206
Current liabilities	(115,574)	(38,848)
Non-current liabilities	(78,720)	(26,461)
Net liabilities	(160,957)	$ (54,103)

On February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. On May 11, 2004, the Argentine government increased the tax to 25 percent. The tax is applied on the sales value after the tax, thus the net effect of the 20 and 25 percent rates is 16.7 and 20 percent, respectively. On August 6, 2004, the Argentine government further increased the export tax rates for oil exports. The export tax now escalates from 25 percent (20 percent effective rate) to a maximum rate of 45 percent (31 percent effective rate) of the realized value for exported barrels as West Texas Intermediate posted prices per Bbl increase from less than $32.00 to $45.00 and above. This tax is limited by law to a maximum term through February 2007.

We currently export approximately 35 percent of our Argentine oil production; however, in 2004, we exported approximately 48 percent. The U.S. dollar equivalent value for domestic Argentine oil sales (now paid in pesos) has generally moved toward parity with the U.S. dollar-denominated export values, net of the export tax. The export tax is deducted for income tax purposes but is not deducted in the calculation of royalty payments.

In accordance with Executive Decree 1589/89, companies engaged in oil and gas production activities are granted the right to freely sell and dispose of their hydrocarbons production. Furthermore, companies are entitled to collect export sales proceeds outside of Argentina and maintain up to 70 percent of U.S. dollar collections outside the country. According to the decree, companies should repatriate the remaining 30 percent of export collections through the exchange markets of Argentina. This requirement places no significant limitations on us based upon our cash flow projections.

Beginning in December 2001, as a result of the economic crisis in the country, Argentina enacted several emergency decrees, including the reinstatement of foreign exchange controls and the mandatory repatriation of most export proceeds. The emergency decrees created some confusion in relation to the regime established under Executive Decree 1589/89, which allows hydrocarbons producers to retain 70 percent of their export collections outside of Argentina. In order to address this matter, Executive Decree No. 2703/02 was issued on December 27, 2002, which confirmed the right to maintain 70 percent of export proceeds outside the country effective January 1, 2003, and therefore did not address transactions which occurred during 2002 after the emergency decrees. We have collected and maintained as much as 70 percent of export proceeds in U.S. dollar bank accounts under the regime established by Executive Decree No. 1589/89 including transactions which occurred during 2002. Although we believe we have acted in accordance with the emergency measures and Executive Decrees in place during 2002, we are aware that the Argentine Central Bank has inquired about certain transactions made by other producers related to retention of export proceeds outside the country during the period in question.

On November 5, 2004, we received a letter from the Ministry of Economy of the Argentine Province of Santa Cruz requesting that royalty payments made since March 2002 be amended to eliminate the market impact of the Argentine export tax on sales to domestic refiners. We believe this request is made without merit, as royalties are calculated and paid on the actual prices received from third party purchasers.

On December 24, 2004 the Secretary of Energy issued Administrative Resolution 1679/2004, in order to alleviate shortages in domestic diesel markets by insuring adequate oil supplies to Argentine refiners. The terms of the resolution require producers to submit evidence to the Secretary of Energy that its oil to be exported has been offered to domestic refiners prior to the government's issuance of export permission.

After a year of negotiations, on January 24, 2003, the International Monetary Fund ("IMF") executed a transitional $6.8 billion, eight-month stand-by credit arrangement to provide financial stability through the presidential elections. After a successful transition of government, and as a result of restoring a measure of economic stability and growth during 2002, in September 2003, the IMF approved a $13.5 billion stand-by credit arrangement, to be disbursed in stages over a three-year period, to succeed the transitional arrangement that expired on August 31, 2003. The economic program to which the Argentine government and the IMF agreed is based on a fiscal framework to meet growth, employment, and social objectives, while providing a basis for normalizing relations with creditors and ensuring debt sustainability. Additionally, they agreed to a strategy to assure strengthening of the banking system, to facilitate increases in bank lending, and to further institutional and tax reforms to facilitate corporate debt restructuring and fundamental improvements to the investment climate. On January 28, 2004, the IMF completed and approved its first review of Argentina's performance under the three-year program. On March 22, 2004, the second review and disbursement of the next $3.1 billion tranche was approved. A third review is pending and is expected to be completed during 2005. On January 12, 2005, the Argentine government announced a debt swap offer to external creditors. The offer commenced on January 14, 2005 and concluded on February 25, 2005.

On March 3, 2005, the Argentine government announced a successful conclusion to the sovereign debt swap, reporting that 76 percent of bond holders will participate in the exchange. The bonds declared in default in December 2001 have a face value of US$81.8 billion, and including unpaid interest, now amount to approximately US$103 billion. The debt offered in exchange will be issued in April 2005 for approximately US$35.2 billion. After completion of the transaction, total public debt-service costs will be reduced from approximately US$10 billion to approximately US$3 billion per year. Since good faith negotiations with bond holders and public debt restructuring were important steps for continued negotiations with the IMF, it appears more likely that Argentina and the IMF will be able to either modify the stand-by credit arrangement in place or negotiate a new agreement during the near term. It is also likely that other issues outstanding between Argentina and the IMF must still be addressed prior to a new agreement, such as an increase to public utility tariffs, a new loan to govern the fiscal relationship between the federal government and provinces and reform of the banking system.

On January 2, 2003, at the Argentine government's request, crude oil producers and refiners agreed to limit amounts payable for certain domestic sales occurring during the first quarter of 2003 to a maximum $28.50 per Bbl. The producers and refiners further agreed that the difference between the West Texas Intermediate posted price and the maximum price would be payable once the West Texas Intermediate posted price fell below the maximum. The debt payable under the agreement accrues interest at eight percent. The total debt will be collected by invoicing future deliveries at $28.50 per Bbl after the West Texas Intermediate posted price falls below the maximum price. Additionally, the agreement allowed for renegotiation if the West Texas Intermediate reference price exceeded $35.00 per Bbl for 10 consecutive days, which occurred on February 24, 2003.

On February 25, 2003, the agreement between the producers and the refiners was modified to limit the amount payable from refiners to producers for deliveries occurring between February 26, 2003, and March 31, 2003. While the $28.50 per Bbl payable maximum was maintained, under the modified terms refiners have no obligation to pay producers for sales values that exceed $36.00 per Bbl. Furthermore, interest for debts established during this period was reduced to seven percent. This agreement expired on April 30, 2004. Through December 31, 2004, the accumulated balance of amounts which we may charge to domestic oil purchasers in Argentina, if the West Texas Intermediate posted price decreases below the established maximum price in the future, was approximately $6.8 million, excluding interest. We do not have the right to invoice for such amounts until such time as the West Texas Intermediate posted price declines below the established price cap of $28.50. Accordingly, we have adopted a revenue recognition accounting policy for this potential revenue in which we will record such revenue only upon the receipt of payment for this additional billing due to the uncertainty of recovery of such amounts and the timing thereof. During 2004, we did not record any revenue under this agreement. During 2003, we collected and recorded revenue of approximately $251,000. Such amounts represented all amounts we were entitled to invoice under the agreement.

We sold approximately 0.6 MMBbls of our net Argentine oil production (approximately six percent) under this agreement during 2004 and cumulatively, we have sold approximately 2.0 MMBbls of net oil production under the agreement. We have not recorded revenue nor a receivable for any amounts above the $28.50 per Bbl maximum that have not yet been received. Repayments received from refiners will be recorded as revenues when received. As of December 31, 2004, we had an unbilled potential recovery of approximately $6.8 million under this agreement, excluding interest. During 2004 and 2003, we collected and recognized in revenue zero and approximately $251,000, respectively, under such agreement.

Bolivia. Since replacing former President Gonzalo Sanchez de Lozada, who was forced to resign during October 2003, current President Carlos Mesa has been forced on several occasions to make changes to his cabinet team due to continued political pressure from rival political parties and associated social unrest. After a transportation strike and demonstrations by university students and government pensioners that were held in April 2004, labor unions began threatening to escalate unrest by announcing general strikes during May 2004. On July 18, 2004, voters approved President Mesa's public referendum on several proposed changes in Bolivia's Hydrocarbon Law, including the export of Bolivian gas.

As a result of the referendum, on July 30, 2004, President Mesa presented his proposed Hydrocarbons Law reform bill to the Bolivian congress for consideration. This proposal includes both increased state control over hydrocarbons commercialization and a new taxation regime. Since then, debate has been ongoing and members of congress and rival political parties have proposed changes to President Mesa's reform bill. In early March 2005, political tensions escalated as the Bolivian congress voted among rival proposals concerning the bill's new taxation regime. Leftist opposition groups, led by Evo Morales, have demanded that President Mesa's taxation reform proposals be abandoned in favor of increasing royalty rates from the current 18 percent level to a new rate of 50 percent. On March 7, 2005, President Mesa submitted his letter of resignation to the Bolivian congress in protest of the proposal and in response to demonstrations and blockades initiated by the opposition groups. On March 8, 2005, in a strong show of support for President Mesa, the congress voted unanimously to reject his resignation. However, the opposition groups led by Morales have not yet agreed to abandon their competing Hydrocarbons Law proposal.

In March 2004, the Bolivian government enacted a new tax on all banking transactions, except for payments made to the Bolivian government. The tax is effective for two years beginning July 1, 2004, and will be 0.3 percent for the first year and 0.25 percent the second year. We do not expect this tax to have a significant impact on future periods.

During August 2004, in response to protests concerning high oil prices, the Bolivian government issued Decree 27691, which limited the amounts that condensate producers could invoice Bolivian refiners to a maximum price of $27.11 per Bbl. The decree also established a floor price of $24.53 per Bbl.

On January 7, 2005, the Bolivian government issued Executive Decree 27967, stating that prices in the internal Bolivian gas distribution market could not exceed the average of the last three natural gas purchase agreements registered with the Superintendent of Hydrocarbons. In accordance with the Executive Decree on February 3, 2005, the Superintendent of Hydrocarbons issued Resolution SSDH 124-2005 determining the new maximum price in the Bolivian gas distribution market to be US$0.80 per Mcf, effective February 4, 2005, and its terms are effective until April 30, 2006. All natural gas purchase agreements in place with Bolivian local distribution companies prior to the resolution are required to lower their price in accordance with the terms of the new resolution. In 2005 and 2006, we have contracted volumes of 1.0 Bcf and 0.3 Bcf, respectively which are impacted by the decree. Also, we expect that our 2005 and 2006 revenues will be reduced by approximately $230,000 and $100,000, respectively, as a result of the current resolution.

Bolivian gas markets have historically been limited to exports to Brazil via the Bolivia-to-Brazil gas pipeline and to those internal gas sales necessary to meet Bolivian industrial and consumer demand. We are working to increase sales in both of these areas and we currently have capacity to deliver gas volumes in excess of our contracted volumes. The current daily productive capacity of our properties in Bolivia is approximately 45 MMcf of gas, gross and 28 MMcf of gas, net. During the past several years, Bolivian gas reserve growth has exceeded the demand growth in Bolivia's existing markets. Therefore, we believe substantial competition for gas markets will continue at least until new market areas are established. On April 21, 2004, the Argentine and Bolivian governments agreed to a gas supply arrangement for 141 MMcf per day of gas to Argentina for a six-month period beginning in May 2004, and in July 2004, the government signed a letter of intent to increase those exports by 88 MMcf per day. As a result, our Bolivian sales volumes have increased in the third quarter of 2004. However, it is unclear if these increased sales volumes will continue in future periods. On October 14, the Argentine and Bolivian governments signed a letter of intent for Bolivia to export up to 706 MMcf per day, which is estimated to commence during 2006. This additional quantity is subject to the successful conclusion of a Hydrocarbon Law reform which proves to be acceptable to investors. With the June 2004 approval from the Bolivian public in the referendum on the matter of gas exports, we believe that new projects, such as exports to Mexico and the U.S., as well as additional exports to Argentina, will become feasible in the future, also subject to the successful conclusion of a Hydrocarbon Law reform which proves to be acceptable to investors.

In 1987, the Boliviano replaced the peso and became Bolivia's currency. 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 exchange rate at December 31, 2004, was 8.06 Bolivianos to one U.S. dollar. Since our gas revenues are received in U.S. dollars, we believe that any currency risk associated with our Bolivian operations would not have a material impact on our financial position or results of operations.

Yemen. Yemen has been classified as a low-income developing country by the World Bank. Trade and other external economic links have been limited, with the exception of the oil sector, which accounts for more than 25 percent of Yemen's gross domestic product. The production sharing agreements under which private investors operate are clear and unambiguous, resulting in most of the country's foreign investment being concentrated in the oil sector. The government has relaxed the broader regulatory environment to encourage additional foreign investments. However, obstacles such as an insufficient infrastructure continue to exist. Necessary economic reforms began during 1995 and were supported by both the IMF and the World Bank. The reforms were targeted to enable a more market-based and private sector driven economy and more integration into world markets, all within the context of broad financial and macro-economic stability. These reforms continue to influence Yemen's economic policies today.

Yemen has taken significant steps to stabilize its political environment since the end of its civil war in 1994. The government is dominated by northern Yemen, located in the capital city of Sana'a and headed by President Ali Abdullah Saleh, who is a member of the General People's Congress. The General People's Congress has held power since the mid-1990's and regime change is considered to be unlikely. Civil society is relatively weak and tribal structures remain powerful. Concerns about terrorism and kidnappings are ongoing security risks. Further concerns about continued implementations of economic reform measures as well as increased government control are ongoing business risks. We have evaluated the risk of operating in Yemen and we believe that the current risks are manageable.

Item 8. Financial Statements and Supplementary Data.

Our consolidated Financial Statements and notes thereto, the report of our independent auditors and our supplementary financial information are included elsewhere in this Form 10-K.

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

None.

Item 9A. Controls and Procedures.

We carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended) as of December 31, 2004. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective to ensure that information required to be disclosed by us in our periodic filings under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. As reported in our Form 10-Q for the three month and nine month period ended September 30, 2004, we identified a material weakness in our internal control over financial reporting as of September 30, 2004. The material weakness was the failure of our monitoring control review to detect a material computation error in a hedge effectiveness worksheet, which error was significant to our consolidated financial statements and was not detected prior to our third quarter earnings press release. The error was detected and corrected prior to the filing of our Form 10-Q. This material weakness was remediated during the fourth quarter through a complete review by management of the hedge analysis process and related worksheets and an improvement in our monitoring control reviews over such computations. During the fourth quarter of 2004, there were no other changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's report on internal control over financial reporting as of December 31, 2004 is included on page 73 of this Form 10-K. The attestation report of our independent registered public accounting firm is included on page 74 of this Form 10-K.

Item 9B. Other Information.

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

The information required by Item 401 of Regulation S-K with respect to our Directors is incorporated by reference from the section of our definitive Proxy Statement for our 2005 Annual Meeting of Stockholders (the "Proxy Statement") entitled "Election of Directors." The information required by Item 401 of Regulation S-K with respect to our Executive Officers appears at Item 4A of Part I of this Form 10-K. The information required by Item 405 of Regulation S-K is incorporated by reference from the section of our Proxy Statement entitled "Section 16(a) Beneficial Ownership Reporting Compliance."

Code of Ethics. We have adopted a Code of Ethics for our Chief Executive Officer and senior financial officers. The Code of Ethics is publicly available on our website at http://www.vintagepetroleum.com. If we make any substantive amendments to the Code of Ethics or grant any waiver, including any implicit waiver, from a provision of the Code of Ethics to our Chief Executive Officer, Chief Financial Officer or Corporate Controller, we will disclose the nature of such amendment or waiver on that website.

Item 11. Executive Compensation.

The information required by this Item is incorporated by reference from the sections of our Proxy Statement entitled "Election of Directors" and "Executive Compensation."

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this Item, other than the information required by Item 201(d) of Regulation S-K, is incorporated by reference from the section of our Proxy Statement entitled "Principal Stockholders and Security Ownership of Management." The information required by Item 201(d) of Regulation S-K is set forth below.

Equity Compensation Plan Information

The following table provides information as of December 31, 2004, concerning shares of our common stock authorized for issuance under our existing equity compensation plans.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	(b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))
Equity compensation plans approved by security holders	1,662,967(1)	$ 11.12(1)	4,241,851(2)
Equity compensation plans not approved by security holders	-	-	-
Total	1,662,967	$ 11.12	4,241,851

(1) Includes 149,667 shares subject to non-vested stock rights. The weighted average exercise price does not take these rights into account.

(2) Represents the total number of shares available for issuance under our 1990 Stock Plan pursuant to stock options, stock appreciation rights or non-vested stock or non-vested stock rights. All of the 4,241,851 shares available for issuance under our 1990 Stock Plan may be awarded as non-vested stock or non-vested stock rights. Under the 1990 Stock Plan, 10 percent of the total number of outstanding shares of our common stock, less the total number of shares of our common stock subject to outstanding awards under any other stock-based plan for our employees or our directors, is available for issuance to our key employees and our directors.

Item 13. Certain Relationships and Related Transactions.

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

Item 14. Principal Accountant Fees and Services.

The information required by this Item is incorporated by reference from the sections of our Proxy Statement entitled "Fees of Independent Registered Public Accounting Firm" and "Audit Committee Pre-Approval Policy."

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) (1) Financial Statements:

Our consolidated financial statements and reports of independent registered public accounting firm 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 $0.005 per share (Filed as Exhibit 4.1 to the S-1 Registration Statement).

4.2 Indenture dated as of May 30, 2001, between JPMorgan Chase Bank (formerly 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).

4.3 Indenture dated as of May 2, 2002, between JPMorgan Chase Bank, as Trustee, and the Company (Filed as Exhibit 4.1 to the Company's Registration Statement on Form S-4, Registration No. 333-89182).

4.4 Rights Agreement, dated March 16, 1999, between the Company and Mellon Investor Services LLC (formerly 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).

4.5 First Amendment to Rights Agreement, dated as of April 3, 2002, between the Company and Mellon Investor Services LLC (formerly ChaseMellon Shareholder Services, L.L.C.), as Rights Agent (Filed as Exhibit 4.1 to the Company's Amendment No. 1 to Registration Statement on Form 8-A, filed April 3, 2002).

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

10.1* 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).

10.2* 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).

10.3* 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).

10.4* 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).

10.5* 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).

10.6* 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).

10.7* 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).

10.8* 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).

10.9* Amendment No. 7 to Vintage Petroleum, Inc. 1990 Stock Plan dated January 27, 2005.

10.10* 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")).

10.11* 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).

10.12* 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).

10.13* 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).

10.14* Form of Restricted Stock Award Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.3 to the Company's report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).

10.15* Form of Restricted Stock Rights Award Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.1 to the Company's report on Form 10-Q for the quarter ended September 30, 2002, filed November 14, 2002).

10.16* Form of Restricted Stock Rights Award Agreement for executive officers under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.2 to the Company's report on Form 10-Q for the quarter ended June 30, 2004, filed August 6, 2004).

10.17* Form of Restricted Stock Award Agreement under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10.3 to the Company's report on Form 10-Q for the quarter ended June 30, 2004, filed August 6, 2004).

10.18* Form of Restricted Stock Award Agreement for non-employee directors under the Vintage Petroleum, Inc. 1990 Stock Plan (Filed as Exhibit 10 to the Company's current report on Form 8-K dated November 9, 2004, filed November 10, 2004).

10.19* Form of Restricted Stock Rights Award Agreement for non-employee directors under the Vintage Petroleum, Inc. 1990 Stock Plan.

10.20* Vintage Petroleum, Inc. Amended and Restated Discretionary Performance Bonus Program.

10.21* Vintage Petroleum, Inc. Performance-Based Cash Bonus Program for Chief Executive Officer.

10.22* Separation Agreement and Release dated March 3, 2004, between the Company and S. Craig George (Filed as Exhibit 10.1 to the Company's report on Form 10-Q for the quarter ended March 31, 2004, filed May 7, 2004).

10.23 Credit Agreement dated as of May 2, 2002, among the Company, as borrower, and certain commercial lending institutions, as lenders, Bank of Montreal, as agent, and the Syndication Agent and Co-Documentation Agents party thereto (Filed as Exhibit 10.1 to the Company's report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).

10.24 First Amendment to Credit Agreement dated as of May 24, 2002, among the Company, as borrower, the lenders party thereto, Bank of Montreal, as administrative agent, Deutsche Bank Trust Company Americas, as syndication agent, and Fleet National Bank, Societe Generale and The Bank of New York, as co-documentation agents (Filed as Exhibit 10.2 to the Company's report on Form 10-Q for the quarter ended June 30, 2002, filed August 9, 2002).

10.25 Second Amendment to Credit Agreement dated as of May 24, 2002, among the Company, as borrower, the lenders party thereto, Bank of Montreal, as administrative agent, Deutsche Bank Trust Company Americas, as syndication agent, and Fleet National Bank, Societe Generale and The Bank of New York, as co-documentation agents (Filed as Exhibit 10.1 to the Company's report on Form 10-Q for the quarter ended June 30, 2003, filed August 8, 2003).

10.26 Third Amendment to Credit Agreement dated as of May 12, 2004, among the Company, as borrower, the lenders party thereto, Bank of Montreal, as administrative agent, Deutsche Bank Trust Company, as syndication agent, and Fleet National Bank, Societe Generale and the Bank of New York, as co-documentation agents (Filed as Exhibit 10.1 to the Company's report on Form 10-Q for the quarter ended June 30, 2004, filed August 6, 2004).

10.27 Stock Purchase Agreement dated September 22, 2004, among Midnight Oil & Gas Ltd., as Purchaser, and Vintage Petroleum Canada Investments ULC, Vintage Canada Oil & Gas ULC, and Vintage South America Holdings, Inc., as Sellers (Filed as Exhibit 2.1 to the Company's report on Form 10-Q for the quarter ended September 30, 2004, filed November 9, 2004).

10.28 Stock Purchase Amending and Assignment Agreement dated October 20, 2004, among Midnight Oil & Gas Ltd., as Assignor, Vintage Petroleum Canada Investments ULC, Vintage Canada Oil & Gas ULC, and Vintage Petroleum South America Holdings, Inc., as Sellers, and Daylight Acquisition Corp, as Assignee (Filed as Exhibit 2.2 to the Company's report on Form 10-Q for the quarter ended September 30, 2004, filed November 9, 2004).

21. Subsidiaries of the Company.

23.1 Consent of Ernst & Young LLP.

23.2 Consent of Netherland, Sewell & Associates, Inc.

23.3 Consent of DeGolyer and MacNaughton.

23.4 Consent of DeGolyer and MacNaughton Canada Limited.

31.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(a) and Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Certification of Chief Executive Officer pursuant to Rule 13a-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.

* Management contract or compensatory plan or arrangement.

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 11, 2005

By: /s/ C. C. Stephenson, Jr.
C. C. Stephenson, Jr.
Chairman of the Board, President
and Chief Executive Officer

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, Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	March 11, 2005
/s/ William L. Abernathy William L. Abernathy	Director, Executive Vice President and Chief Operating Officer	March 11, 2005
/s/ William C. Barnes William C. Barnes	Director, Executive Vice President, Chief Financial Officer, Secretary and Treasurer (Principal Financial Officer)	March 11, 2005
/s/ Rex D. Adams Rex D. Adams	Director	March 11, 2005
/s/ Bryan H. Lawrence Bryan H. Lawrence	Director	March 11, 2005
/s/ Joseph D. Mahaffey Joseph D. Mahaffey	Director	March 11, 2005
/s/ Gerald J. Maier Gerald J. Maier	Director	March 11, 2005
/s/ John T. McNabb, II John T. McNabb, II	Director	March 11, 2005
/s/ Michael F. Meimerstorf Michael F. Meimerstorf	Vice President and Controller (Principal Accounting Officer)	March 11, 2005

INDEX TO FINANCIAL STATEMENTS

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

REPORT OF MANAGEMENT ON ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States. The Company's internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States, and that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedure may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*. Management's assessment included evaluation of the design and testing of the operational effectiveness of the Company's internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of the Company's Board of Directors.

Based on our assessment and those criteria, management believes that, as of December 31, 2004, the Company's internal control over financial reporting is effective.

Ernst & Young LLP, the Company's independent registered public accounting firm, has issued an attestation report on management's assessment of the Company's internal control over financial reporting. That report appears on page 74.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

We have audited management's assessment, included in the accompanying Report of Management on Assessment of Internal Control Over Financial Reporting, that Vintage Petroleum, Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO criteria"). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's consolidated balance sheets as of December 31, 2004 and 2003 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, 2004, and our report dated March 11, 2005 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Tulsa, Oklahoma
March 11, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of Vintage Petroleum, Inc. and subsidiaries as of December 31, 2004 and 2003, 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, 2004. 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 the standards of the Public Company Accounting Oversight Board (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 consolidated financial position of Vintage Petroleum, Inc. and subsidiaries as of December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States.

As discussed in Note 1 to the consolidated financial statements, effective January 1, 2003, the Company adopted the provisions of Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations.* In addition, as also discussed in Note 1, effective January 1, 2002, the Company adopted the provisions of Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Vintage Petroleum, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 11, 2005, expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Tulsa, Oklahoma
March 11, 2005

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

	December 31, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 124,221	$ 32,264
Accounts receivable -		
Oil and gas sales	107,870	78,321
Joint operations	12,479	7,480
Income taxes receivable	31,571	7,421
Prepaids and other current assets	23,648	6,660
Deferred income taxes	15,364	-
Assets of discontinued operations	-	224,321
Total current assets	315,153	356,467
PROPERTY, PLANT AND EQUIPMENT, at cost:		
Oil and gas properties, successful efforts method	2,163,176	1,835,588
Oil and gas gathering systems and plants	23,926	23,344
Other	31,932	26,334
	2,219,034	1,885,266
Less accumulated depreciation, depletion and amortization	942,656	829,055
Total property, plant and equipment, net	1,276,378	1,056,211
DEFERRED INCOME TAXES	13,200	-
OTHER ASSETS, net	40,161	41,581
TOTAL ASSETS	$ 1,644,892	$ 1,454,259

The accompanying notes are an integral part of these statements.

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

	December 31, 2004	December 31, 2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Revenue payable	$ 33,740	$ 22,641
Accounts payable - trade	50,775	41,893
Current income taxes payable	23,565	23,545
Derivative financial instrument payable	27,672	7,551
Other payables and accrued liabilities	73,748	61,507
Liabilities of discontinued operations	-	47,286
Total current liabilities	209,500	204,423
LONG-TERM DEBT	549,949	699,943
DEFERRED INCOME TAXES	80,383	41,234
LONG-TERM LIABILITY FOR ASSET RETIREMENT OBLIGATIONS	90,707	72,158
OTHER LONG-TERM LIABILITIES	30,675	14,015
COMMITMENTS AND CONTINGENCIES (Note 4)		
STOCKHOLDERS' EQUITY, per accompanying statements:		
Preferred stock, $0.01 par, 5,000,000 shares authorized, zero shares issued and outstanding	-	-
Common stock, $0.005 par, 160,000,000 shares authorized, 66,541,984 and 64,720,975 shares issued and 66,012,252 and 64,281,199 outstanding, respectively	333	324
Capital in excess of par value	361,120	337,080
Retained earnings	342,707	22,844
Accumulated other comprehensive income (loss)	(13,088)	70,482
	691,072	430,730
Less treasury stock, at cost, 529,732 and 439,776 shares, respectively	4,319	3,117
Less unamortized cost of non-vested stock awards	3,075	5,127
Total stockholders' equity	683,678	422,486
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,644,892	$ 1,454,259

The accompanying notes are an integral part of these statements.

VINTAGE PETROLEUM, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share amounts)

	For the Years Ended December 31,		
	2004	2003	2002
REVENUES:			
Oil, condensate and NGL sales	$ 516,756	$ 428,350	$ 380,032
Gas sales	188,582	114,049	83,902
Sulfur sales	1,366	1,715	653
Gas marketing	71,476	70,633	54,391
Total revenues	778,180	614,747	518,978
COSTS AND EXPENSES:			
Production costs	141,040	124,367	111,925
Transportation and storage costs	11,086	7,401	7,011
Production and ad valorem taxes	23,007	17,469	15,420
Export taxes	43,050	31,041	24,824
Exploration costs	31,993	21,607	22,942
Gas marketing	67,601	68,038	52,781
General and administrative	56,473	46,908	38,574
Stock compensation	7,619	5,259	845
Depreciation, depletion and amortization	103,202	87,814	104,872
Impairment of proved oil and gas properties	6,049	6,050	16,972
Accretion	6,626	5,980	-
Other operating expense	2,327	6,067	6,061
Total costs and expenses	500,073	428,001	402,227
OPERATING INCOME	278,107	186,746	116,751
NON-OPERATING (INCOME) EXPENSE:			
Interest expense	51,815	69,834	77,314
Loss on early extinguishment of debt	9,903	6,909	8,154
Derivative losses	21,745	1,539	465
(Gain) loss on disposition of assets	(155)	1,194	(16,553)
Foreign currency exchange (gain) loss	(775)	6,710	(269)
Other non-operating (income) expense	644	(788)	(2,065)
Net non-operating expense	83,177	85,398	67,046
Income from continuing operations before income taxes and cumulative effect of changes in accounting principles	194,930	101,348	49,705
INCOME TAX PROVISION (BENEFIT):			
Current	57,906	40,140	16,008
Deferred	11,583	1,714	(1,274)
Total income tax provision	69,489	41,854	14,734
Income from continuing operations before cumulative effect of changes in accounting principles	125,441	59,494	34,971
INCOME (LOSS) FROM DISCONTINUED OPERATIONS, net of income tax benefit of $30,722, $112,902 and $47,865, respectively	207,151	(307,520)	(118,088)
Income (loss) before cumulative effect of changes in accounting principles	332,592	(248,026)	(83,117)
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, net of income tax provision of zero, $4,104 and zero, respectively	-	7,119	(60,547)
NET INCOME (LOSS)	$ 332,592	$ (240,907)	$ (143,664)

The accompanying notes are an integral part of these statements.

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

	For the Years Ended December 31, 2004	2003	2002
BASIC INCOME (LOSS) PER SHARE:			
Income from continuing operations before cumulative effect of changes in accounting principles	$ 1.93	$ 0.93	$ 0.55
Income (loss) from discontinued operations	3.18	(4.80)	(1.86)
Income (loss) before cumulative effect of changes in accounting principles	5.11	(3.87)	(1.31)
Cumulative effect of changes in accounting principles	-	0.11	(0.96)
Net income (loss)	$ 5.11	$ (3.76)	$ (2.27)
DILUTED INCOME (LOSS) PER SHARE:			
Income from continuing operations before cumulative effect of changes in accounting principles	$ 1.91	$ 0.92	$ 0.55
Income (loss) from discontinued operations	3.15	(4.77)	(1.86)
Income (loss) before cumulative effect of changes in accounting principles	5.06	(3.85)	(1.31)
Cumulative effect of changes in accounting principles	-	0.11	(0.95)
Net income (loss)	$ 5.06	$ (3.74)	$ (2.26)
Weighted average common shares outstanding:			
Basic	65,046	64,022	63,219
Diluted	65,784	64,497	63,456

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 treasury shares and per share amounts)

	Common Stock Shares	Common Stock Amount	Treasury Stock	Capital In Excess of Par Value	Un-amortized Non-Vested Stock Awards	Retained Earnings	Accumulated Other Compre-hensive Income (Loss)	Total
BALANCE AT DECEMBER 31, 2001	63,081	$ 315	$ -	$ 324,077	$ (1,760)	$ 428,443	$ (21,632)	$ 729,443
Comprehensive loss:								
Net loss	-	-	-	-	-	(143,664)	-	(143,664)
Foreign currency translation adjustment	-	-	-	-	-	-	4,965	4,965
Change in value of derivatives	-	-	-	-	-	-	(11,906)	(11,906)
Total comprehensive loss								(150,605)
Exercise of stock options and tax effects	81	1	-	730	-	-	-	731
Issuance of non-vested stock	271	1	-	2,972	(2,973)	-	-	-
Amortization of non-vested stock awards	-	-	-	204	1,555	-	-	1,759
Forfeiture of non-vested stock and other (84,700 shares)	-	-	-	(1,473)	945	-	-	(528)
Cash dividends declared ($0.155 per share)	-	-	-	-	-	(9,808)	-	(9,808)
BALANCE AT DECEMBER 31, 2002	63,433	317	-	326,510	(2,233)	274,971	(28,573)	570,992
Comprehensive loss:								
Net loss	-	-	-	-	-	(240,907)	-	(240,907)
Foreign currency translation adjustment	-	-	-	-	-	-	92,208	92,208
Change in value of derivatives	-	-	-	-	-	-	6,847	6,847
Total comprehensive loss								(141,852)
Issuance of stock options	-	-	-	117	-	-	-	117
Exercise of stock options and tax effects	176	1	-	1,624	-	-	-	1,625
Issuance of non-vested stock	1,090	6	-	8,955	(8,961)	-	-	-
Amortization of non-vested stock awards	-	-	-	865	5,445	-	-	6,310
Forfeiture of non-vested stock (77,963 shares)	-	-	-	(991)	622	-	-	(369)
Vesting of stock rights	22	-	-	-	-	-	-	-
Purchase of treasury stock (277,113 shares)	-	-	(3,117)	-	-	-	-	(3,117)
Cash dividends declared ($0.175 per share)	-	-	-	-	-	(11,220)	-	(11,220)
BALANCE AT DECEMBER 31, 2003	64,721	324	(3,117)	337,080	(5,127)	22,844	70,482	422,486
Comprehensive income:								
Net income	-	-	-	-	-	332,592	-	332,592
Foreign currency translation adjustment	-	-	-	-	-	-	16,853	16,853
Sale of Canadian operations	-	-	-	-	-	-	(89,404)	(89,404)
Change in value of derivatives	-	-	-	-	-	-	(11,019)	(11,019)
Total comprehensive income								249,022
Modification of stock option terms	-	-	-	379	-	-	-	379
Exercise of stock options and tax effects	1,473	7	-	16,485	-	-	-	16,492
Issuance of non-vested stock	176	1	-	2,651	(2,652)	-	-	-
Amortization of non-vested stock awards	-	-	-	4,756	4,601	-	-	9,357
Forfeiture of non-vested stock (17,459 shares)	-	-	-	(230)	103	-	-	(127)
Vesting of stock rights	172	1	-	(1)	-	-	-	-
Purchase of treasury stock (72,497 shares)	-	-	(1,202)	-	-	-	-	(1,202)
Cash dividends declared ($0.195 per share)	-	-	-	-	-	(12,729)	-	(12,729)
BALANCE AT DECEMBER 31, 2004	66,542	$ 333	$ (4,319)	$ 361,120	$ (3,075)	$ 342,707	$ (13,088)	$ 683,678

The accompanying notes are an integral part of these statements.

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

	For the Years Ended December 31,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 332,592	$ (240,907)	$ (143,664)
Adjustments to reconcile net income (loss) to cash provided by operating activities -			
(Income) loss from discontinued operations, net of tax	(207,151)	307,520	118,088
Cumulative effect of changes in accounting principles	-	(7,119)	60,547
Depreciation, depletion and amortization	103,202	87,814	104,872
Impairment of proved oil and gas properties	6,049	6,050	16,972
Accretion	6,626	5,980	-
Dry holes and impairments of unproved oil and gas properties	21,227	11,629	19,362
Provision (benefit) for deferred income taxes	11,583	1,714	(1,274)
Foreign currency exchange (gain) loss	(775)	6,710	(269)
(Gain) loss on disposition of assets	(155)	1,194	(16,553)
Loss on early extinguishment of debt	9,903	6,909	8,154
Stock compensation	7,619	5,259	845
Derivative losses	21,745	1,539	465
Other non-cash items included in net income (loss)	844	2,359	1,449
Working capital changes	24,292	15,887	10,000
Cash provided by continuing operations	337,601	212,538	178,994
Cash provided by discontinued operations	14,705	21,295	61,875
Cash provided by operating activities	352,306	233,833	240,869
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures -			
Oil and gas properties	(306,970)	(140,502)	(58,755)
Gathering systems and other	(2,816)	(4,273)	(5,456)
Proceeds from sales of oil and gas properties	668	29,981	23,154
Purchase of companies, net of cash acquired	(26,757)	-	-
Proceeds from sale of company, net of cash sold	241,482	116,107	39,314
Payments on non-hedge derivative transactions	(10,917)	-	-
Other	(319)	3,487	(453)
Cash provided (used) by investing activities - continuing operations	(105,629)	4,800	(2,196)
Cash provided (used) by investing activities - discontinued operations	7,840	(13,289)	(69,176)
Cash used by investing activities	(97,789)	(8,489)	(71,372)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common stock	14,122	1,625	731
Purchase of treasury stock	(1,202)	(3,117)	-
Issuance of 8 1/4% Senior Notes Due 2012	-	-	350,000
Redemption of 9 3/4% Senior Subordinated Notes Due 2009	(157,313)	-	-
Redemption of 9% Senior Subordinated Notes Due 2005	-	(50,750)	(103,000)
Redemption of 8 5/8% Senior Subordinated Notes Due 2009	-	(103,234)	-
Advances on revolving credit facility and other borrowings	715,900	289,100	289,400
Payments on revolving credit facility and other borrowings	(715,900)	(322,900)	(667,000)
Dividends paid ($0.19, $0.17 and $0.15 per share, respectively)	(12,318)	(10,862)	(9,484)
Other	(6,423)	(1,753)	(10,588)
Cash used by financing activities - continuing operations	(163,134)	(201,891)	(149,941)
Cash used by financing activities - discontinued operations	-	-	(11,972)
Cash used by financing activities	(163,134)	(201,891)	(161,913)
EFFECT OF EXCHANGE RATE CHANGE ON CASH	574	686	(2,338)
NET INCREASE IN CASH AND CASH EQUIVALENTS	91,957	24,139	5,246
CASH AND CASH EQUIVALENTS, beginning of period	32,264	8,125	2,879
CASH AND CASH EQUIVALENTS, end of period	$ 124,221	$ 32,264	$ 8,125

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, 2004, 2003 and 2002

1. Business and Significant Accounting Policies

Vintage Petroleum, Inc. is an independent energy company with operations primarily in the exploration and production and gas marketing segments of the oil and gas industry. The Company's United States exploration and production operations include the West Coast, Gulf Coast, East Texas and Mid-Continent areas. The Company also has core operating areas in the San Jorge Basin and Cuyo Basin of Argentina, the Chaco Basin in Bolivia and the S-1 Damis block in Yemen. The Company also has exploration activities currently ongoing in Bulgaria. The Company sold its exploration and production operations in Trinidad, Ecuador and Canada in July 2002, January 2003, and November 2004, respectively (see Note 7).

Consolidation and Presentation

The consolidated financial statements include the accounts of Vintage Petroleum, Inc., its wholly- and majority-owned subsidiaries and its proportionately consolidated general partner and limited partner interests in various joint ventures engaged in exploration and production activities (collectively, the "Company"). All significant intercompany accounts and transactions have been eliminated in consolidation. Certain 2002 and 2003 amounts have been reclassified to conform with the 2004 presentation. These reclassifications had no effect on the Company's net income (loss) or stockholders' equity.

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, the 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 and Unproved Property Impairments

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. Certain costs of exploratory wells are capitalized pending determination that proved reserves have been found. Such determination may be dependent upon the results of planned additional wells and the cost of required capital expenditures to produce the reserves found. 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. Delineation seismic costs incurred to select development locations within a productive oil and gas field are capitalized. The Company recognizes gains or losses on the sale of properties on a field basis.

Unproved leasehold costs are capitalized and reviewed periodically for impairment. Individual unproved properties whose acquisition costs are significant are assessed for impairment on a property-by-property basis, considering factors such as future drilling and exploitation plans and lease terms. For unproved properties whose acquisition costs are not individually significant, the amount of those properties' impairment is determined by amortizing the properties in groups on the basis of the Company's experience in similar situations and other information such as the primary lease terms, the average holding period of unproved properties and the relative proportion of such properties on which proved reserves have been found in the past. Costs related to impaired prospects are charged to expense and included in "exploration costs" in the accompanying statements of operations. The Company recorded leasehold impairments of $4.7 million, $4.3 million and $4.0 million in 2004, 2003 and 2002, respectively, excluding the Company's discontinued operations (see Note 7). Additional impairment expense could result if oil and gas prices decline in the future or if downward reserve revisions are recorded on nearby properties, as it may not be economic to develop some of these unproved properties. The Company's leasehold impairments related to discontinued operations were $4.5 million, $41.6 million and $8.2 million in 2004, 2003 and 2002, respectively.

As of December 31, 2004, the Company had total unproved oil and gas property costs of approximately $25.4 million, consisting of undeveloped leasehold costs of $14.3 million and unevaluated exploratory drilling costs of $11.1 million. Approximately $14.6 million of the total unevaluated costs are associated with the Company's exploration drilling program in Yemen.

Costs of development dry holes and proved leaseholds are amortized on the unit-of-production method using proved reserves on a field basis. The depreciation of capitalized production equipment, drilling costs and asset retirement obligations is based on the unit-of-production method using proved developed reserves on a field basis.

Development Seismic Costs

The Company capitalizes delineation seismic costs incurred to select development drilling locations within a productive oil and gas field as development costs. Exploration seismic costs are expensed as incurred.

The Company capitalized approximately $2.0 million, $1.9 million and $1.7 million of 3-D seismic costs incurred in its development activities in the years ended December 31, 2004, 2003 and 2002, respectively. As of December 31, 2004 a total of approximately $22.0 million (net of accumulated amortization of approximately $6.4 million) of development seismic costs are included in net property, plant and equipment in the accompanying balance sheet.

In connection with a routine review of the Company's 2003 Form 10-K, the Securities and Exchange Commission ("SEC") has evaluated the appropriateness of the Company's accounting policy for development seismic costs. On March 11, 2005, the SEC provided the Company with guidance regarding the application of this accounting policy. Based on a preliminary review of the impact this guidance may have on previously capitalized costs, the Company believes that the impact of any potential adjustment would not be material to any period presented in the accompanying consolidated financial statements.

Exploration Drilling Costs

Costs of drilling exploratory wells are capitalized as part of the Company's unproved costs pending management's determination of whether the wells have found proved reserves. Management makes this determination as soon as possible after completion of drilling considering the guidance provided in Statement of Financial Accounting Standards No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies* ("SFAS 19"). SFAS 19 provides that such costs should not be carried as an asset for more than one year following completion of drilling unless the well has found oil and gas reserves in an area requiring a major capital expenditure before production could begin. In that case, the costs of such exploration well continue to be carried as an asset pending determination of whether proved reserves have been found only as long as the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and drilling of the additional exploratory wells is under way or firmly planned for the near future. If both those conditions are not met, the well costs are charged to expense. Management performs this evaluation on a quarterly basis.

As of December 31, 2004 and 2003, the Company had the following exploration wells capitalized and reported as unevaluated costs:

	December 31, 2004	December 31, 2003
Wells in progress	$ 643	$ 11,330
Drilling completed - less than one year	3,888	1,052
Drilling completed - over one year	6,606	6,606
Total exploration drilling costs	$ 11,137	$ 18,988

As of December 31, 2004, the Company had one exploration well in Yemen on which the drilling was completed for more than one year with a total cost of approximately $6.6 million. Management believes that this well has found sufficient reserves to justify its completion and such well requires a major capital expenditure before production can begin. During 2004, the Company drilled another well in this area as part of the development with plans to further continue development and evaluation of this area during 2005. Depending on the results of such activity, the costs capitalized for the completed wells may be charged to expense during 2005. The Company had no exploration wells capitalized in areas requiring a major capital expenditure before production could begin where additional drilling efforts are not underway or firmly planned and had no exploration wells capitalized in areas not requiring a major capital expenditure where more than one year has elapsed since completion of drilling.

The Financial Accounting Standards Board ("FASB") has recently issued Proposed FASB Staff Position No 19-A, *Accounting for Suspended Well Costs* ("FSP 19-A"). If adopted as proposed, FSP 19-A will amend SFAS 19 to provide that in those situations where exploration drilling has been completed and oil and gas reserves have been found, but such reserves cannot be classified as proved when drilling is complete, the drilling costs may be capitalized if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the enterprise is making sufficient progress assessing the reserves and the economic and operating viability of the project. If either of the criteria is not met, the well is assumed to be impaired and the costs charged to expense. Any well which has not found reserves is charged to expense. Management believes that no adjustment would have been required as of the beginning of and for each of the three years in the period ended December 31, 2004, from the application of the proposed FSP 19-A.

For the years ended December 31, 2004, 2003 and 2002, the changes in capitalized exploratory drilling costs were as follows (in thousands):

	Years Ended December 31, 2004	2003	2002
Balance, beginning of year	$ 18,988	$ 11,953	$ 17,184
Additions	40,156	30,732	16,787
Transferred to proved properties	(31,507)	(16,403)	(8,142)
Expensed	(16,500)	(7,294)	(13,876)
Balance, end of year	$ 11,137	$ 18,988	$ 11,953

Asset Retirement Obligations

In August 2001, FASB issued Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("SFAS 143"). The Company was required to adopt this standard beginning January 1, 2003. Through December 31, 2002, the Company accrued an estimate of future abandonment costs of wells and related facilities through its depreciation calculation and included the cumulative accrual in accumulated depreciation in accordance with the provisions of SFAS 19 and industry practice. At December 31, 2002, approximately $54.6 million of accrued future abandonment costs were included in accumulated depreciation. The new standard requires 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 asset retirement obligations consist primarily of costs associated with the plugging and abandonment of oil and gas wells, site reclamation and facilities dismantlement. However, future abandonment liabilities are also recorded for other assets such as pipelines, processing plants and compressors. A corresponding amount is capitalized as part of the related property's carrying amount. The discounted capitalized asset retirement cost is amortized to expense through the depreciation calculation over the estimated useful life of the asset based on proved developed reserves. The liability accretes over time with a charge to accretion expense. At January 1, 2003, December 31, 2003, and December 31, 2004, there were no assets legally restricted for purposes of settling asset retirement obligations.

The Company adopted SFAS 143 effective January 1, 2003, and recorded an increase in property, plant and equipment of approximately $50.3 million, a decrease in accumulated depreciation, depletion and amortization of approximately $43.9 million, an increase in current asset retirement liabilities of approximately $4.5 million, an increase in long-term asset retirement liabilities of approximately $78.5 million, a $4.1 million increase in deferred income tax liabilities and a non-cash gain as a result of the cumulative effect of change in accounting principle, net of tax, of approximately $7.1 million.

A reconciliation of the liability for asset retirement obligations is as follows (in thousands):

	Years Ended December 31,	
	2004	2003
Liability for asset retirement obligations, beginning of year	$ 76,918	$ -
Initial liability	-	83,040
Reclassification of Canada to discontinued operations	-	(14,614)
New obligations for wells drilled	2,366	1,226
Assets purchased	4,095	-
Costs incurred	(1,657)	(1,929)
Reversal of liability for sales of oil and gas properties	-	(689)
Accretion expense	6,626	5,980
Revisions in estimated cash flows	4,718	3,904
Liability for asset retirement obligations, end of year	$ 93,066	$ 76,918

Of the liability for asset retirement obligations balance at December 31, 2004 and 2003, approximately $2.4 million and $4.8 million, respectively, is classified as current and included in "Other payables and accrued liabilities" in the accompanying balance sheets.

Had the provisions of SFAS 143 been applied in 2002, the liability for asset retirement obligations would have been $75.7 million at January 1, 2002 and $83.0 million at December 31, 2002, and the Company's net loss and loss per share would have been as follows (in thousands, except per share amounts):

	December 31,2002	
	As Reported	Pro Forma
Net loss	$ (143,664)	$ (148,719)
Net loss per share:		
Basic	$ (2.27)	$ (2.35)
Diluted	$ (2.26)	$ (2.34)

Impairments 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 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 price and cost assumptions used for acquisition evaluations. The Company recorded impairment provisions related to its proved oil and gas properties of $6.0 million, $6.1 million and $17.0 million in 2004, 2003 and 2002, respectively, excluding proved property impairments related to discontinued operations in Canada. The Company's proved property impairments related to discontinued operations were zero, $364.1 million and $81.7 million in 2004, 2003 and 2002, respectively. These impairments resulted from downward revisions in the estimates of proved oil and gas reserves in certain U.S. and Canadian properties in the fourth quarter of 2004, the second, third and fourth quarters of 2003, and the fourth quarter of 2002. Disappointing results in Canada during 2003 led to significant downward reserve revisions at year end 2003. Results of the Company's work programs and production performance of certain producing properties during the latter part of 2003 resulted in revisions to reserves previously booked to specific wells or to reserves associated with future activities.

Goodwill

Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis Exploration Ltd. ("Genesis") in May 2001 (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 assessed the recoverability of goodwill by determining whether the net book value of goodwill could 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 estimated future net revenues of the acquired properties included 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 expectation of future oil and gas prices and costs, consistent with price and cost assumptions used for acquisition evaluations. There was no impairment of goodwill in 2001 under this method.

On July 20, 2001, the FASB issued Statement of Financial Accounting Standards No. 141, *Business Combinations* ("SFAS 141"), and Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* ("SFAS 142"). SFAS 141 requires all business combinations initiated after June 30, 2001, to be accounted for using the purchase method of accounting. 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. 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.

The Company's acquisition of Genesis was accounted for using the purchase method of accounting. The Company adopted SFAS 141 and SFAS 142 effective January 1, 2002, resulting in the elimination of goodwill amortization from statements of operations in future periods. Upon adoption, the Company recorded an impairment charge of $60.5 million related to the goodwill of its Canadian operations as a cumulative effect of a change in accounting principle in its statement of operations (see Note 7). The Company recorded additional goodwill impairment charges of $25.7 million and $76.4 million at December 31, 2003 and 2002, respectively. The Company had no remaining goodwill recorded at December 31, 2003. The Company sold its operations in Canada in November 2004 (see Note 7) and the goodwill impairment charges of $25.7 million and $76.4 million discussed above are now included in income (loss) from discontinued operations in the accompanying statements of operations.

Revenue Recognition

The Company's principal revenue source is the sale of crude oil, condensate, natural gas liquids and natural gas. In general, the amount recorded as revenue from the sale of such products represents the estimated amount due based on the Company's interest in the properties and the agreements with the respective purchasers. The amount reported as revenue in the accompanying statement of operations is also affected by the results of oil and gas hedging activities, as discussed below.

Crude oil, condensate and natural gas liquid revenues are recorded at the time of delivery of such products to pipelines for the account of the purchaser or at the time of physical transfer of such products to the purchaser.

A portion of the Company's domestic oil sales in Argentina were previously subject to a domestic price cap agreement, relating to deliveries occurring between February 26, 2003 and April 30, 2004. Under the agreement, if the $28.50 price cap is less than the West Texas Intermediate posted price as quoted on the Platt's Crude Oil Marketwire at the time of sale, the Company is entitled to charge the oil purchasers for such difference only when the West Texas Intermediate posted price is less than the $28.50 price cap in future periods. The Company does not record any revenue under such price cap agreement until such time as the billed amounts are actually received. As of December 31, 2004, the Company had an unbilled potential recovery of approximately $6.8 million under this agreement, excluding interest. During 2004, the Company did not record any revenues under this agreement. During 2003, the Company collected and recognized revenue of approximately $251,000 under such agreement. Such amounts represented all amounts the Company was entitled to invoice under the agreement.

Revenues from the sale of natural gas are recorded using the sales method. Under such method, the Company recognizes revenue from the sale of natural gas production from properties, including properties in which it owns an interest with other producers, based on the actual volumes the Company sold during the period. Such volumes may be more or less than the Company's entitlement share of the volumes produced based on its interest in the properties. Any differences between the volumes sold and the entitlement volumes which are deemed to be unrecoverable through remaining production based on current proved reserve estimates are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are not significant.

Oil inventories held in storage facilities are valued at cost, which is lower than market value. Such inventories totaled $6.8 million and $0.3 million at December 31, 2004 and 2003, respectively.

Transportation and storage costs billed to the Company are reflected as expenses as shown in the accompanying statements of operations.

Derivative Financial Instruments

The Company periodically uses derivative financial instruments in order to reduce the impact of oil and natural gas price fluctuations and generally attempts to qualify such derivatives as cash flow hedges for accounting purposes. The Company accounts for its derivative financial instruments under the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (as amended, "SFAS 133"). SFAS 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. The Company defines fair value as the amount it would receive or pay to settle the derivative at period-end. SFAS 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 treatment.

For derivative financial instruments that qualify as cash flow hedges, the effective portion of the gain or loss on a derivative instrument is reported as a component of other comprehensive income and reclassified into sales revenue in the same period or periods during which the hedged forecasted transaction affects earnings. The effective portion is determined by comparing the cumulative change in fair value of the derivative to the cumulative change in the expected cash flows of the item being hedged. To the extent the cumulative change in the fair value of the derivative exceeds the cumulative change in the expected cash flows, the excess is recognized currently in earnings in non-operating income or expense. If the cumulative change in the expected cash flows exceeds the change in fair value of the derivative, the difference is ignored. Changes in the fair value and settlements of derivative financial instruments that do not qualify, or ceased to qualify, for accounting treatment as hedges, if any, are recognized currently as non-operating income or expense. The cash flows from derivative financial instruments that do not qualify for hedge accounting are included in investing activities in the consolidated statements of cash flows.

Derivative losses included in income from continuing operations consist of the following (in thousands):

	Year Ended December 31,		
	2004	2003	2002
Cash settlements under derivative instruments that did not qualify, or ceased to qualify, for hedge accounting	$ 10,917	$ -	$ -
Changes in the fair value of derivative instruments that did not qualify, or ceased to qualify, for hedge accounting	8,878	924	-
Hedge ineffectiveness	1,950	615	465
	$ 21,745	$ 1,539	$ 465

Depreciation

Depreciation of property, plant and equipment (other than oil and gas properties) is provided using the straight-line method 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. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

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. Approximately $121.6 million of the Company's cash at December 31, 2004, was held in U.S. banks and is related to the Company's foreign operations. Working capital changes reflected in the operating section of the accompanying cash flow statements consist of the following (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Increase in receivables	$ (32,659)	$ (3,914)	$ (25,370)
Increase in payables and accrued liabilities	53,198	9,836	22,365
Other working capital changes	3,753	9,965	13,005
	$ 24,292	$ 15,887	$ 10,000

During the years ended December 31, 2004, 2003 and 2002, the Company made cash payments for interest totaling $51.5 million, $72.9 million and $74.2 million, respectively. Cash payments for U.S. income taxes of $2.0 million, $48.7 million (primarily related to discontinued operations; see Note 7), and $0.6 million were made during 2004, 2003 and 2002, respectively. Cash payments for Argentine income taxes of $56.9 million, $46.6 million and $8.9 million were made during 2004, 2003 and 2002, respectively.

Income (Loss) Per Share

Basic income (loss) per common share was computed by dividing net income (loss) by the weighted average number of shares outstanding during the period. Diluted income (loss) per common share for all periods presented was computed assuming the exercise of all dilutive options, as determined by applying the treasury stock method, and assuming the vesting of all non-vested stock rights.

The following table reconciles the weighted average common shares outstanding used in the calculations of basic and diluted income (loss) per share (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Weighted average common shares outstanding - Basic	65,046	64,022	63,219
Dilutive effect of potential common shares issuable upon the exercise of outstanding stock options	554	329	197
Dilutive effect of potential common shares issuable upon the vesting of outstanding non-vested stock rights	184	146	40
Weighted average common shares outstanding - Diluted	65,784	64,497	63,456

Certain options to purchase shares of the Company's common stock have been excluded from the dilution calculations because the assumed exercise of these options was antidilutive. The antidilutive options will dilute basic earnings per share in the future, if exercised, and may impact diluted earnings per share in the future depending on the market price of the Company's common stock. The following information relates to these options:

	Years Ended December 31,		
	2004	2003	2002
Options excluded from dilution calculations (in thousands)	8	767	3,069
Range of exercise prices	$21.81 to $22.94	$10.88 to $22.94	$11.05 to $22.94
Weighted average exercise price	$22.09	$15.45	$18.98

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 $3.2 million, $3.1 million and $3.9 million in 2004, 2003 and 2002, respectively.

Export, Production and Ad Valorem Taxes

On February 13, 2002, the Argentine government announced a 20 percent tax on oil exports, effective March 1, 2002. The export tax was increased to 25 percent effective May 11, 2004. The export tax is applied on the sales value after the tax, thus the net effect of the 20 and 25 percent rates is 16.7 and 20 percent, respectively. On August 6, 2004, the Argentine government further increased the export tax rates for oil exports. The export tax now escalates from 25 percent (20 percent effective rate) to a maximum rate of 45 percent (31 percent effective rate) of the realized value for exported barrels as West Texas Intermediate posted prices per barrel as quoted on the Platt's Crude Oil Marketwire increase from less than $32.00 to $45.00 and above. The export tax is deducted for income tax purposes but is not deducted in the calculation of royalty payments. The tax is limited by law to a maximum term through February 2007.

Included in production and ad valorem taxes are the following items (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Gross production taxes	$ 17,191	$ 11,809	$ 9,887
Ad valorem taxes	5,816	5,660	5,533

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 gas marketing activities are classified as revenue payable in the accompanying financial statements.

Accounts Receivable

The Company's oil and gas and gas marketing 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. This concentration of customers and joint interest owners may impact the Company's overall credit risk since those entities may be similarly affected by industry-wide changes in economic or other conditions. Such receivables are not collateralized, non-interest bearing and are generally settled in less than 60 days. The Company has not historically incurred any significant bad debts on such receivables.

Foreign Currency

Foreign currency transactions and financial statements are translated in accordance with Statement of Financial Accounting Standards No. 52, *Foreign Currency Translation*. All of the Company's subsidiaries use the U.S. dollar as their functional currency, except for the Company's Canadian subsidiary which was sold in November 2004. This entity's functional currency was the Canadian dollar. Transaction gains and losses that arise from exchange rate fluctuations applicable to transactions denominated in a currency other than the Company's or its subsidiaries' functional currency are included in the results of operations as incurred.

International investments represent, and are expected to continue to represent, a significant portion of the Company's business. The Company's operations in Argentina represented approximately 41 percent of its 2004 total revenues from continuing operations and approximately 50 percent and 38 percent of the Company's total proved reserves and total assets, respectively, at December 31, 2004.

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, the Argentine government instituted restrictions in early December 2001 that prohibit certain foreign money transfers without Central Bank approval and limit cash withdrawals from bank accounts to personal transactions in small amounts 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 abolished the legal exchange rate of one peso to one U.S. dollar. On January 9, 2002, Decree 71 created a dual exchange market whereby foreign trade transactions were conducted at an official exchange rate of 1.4 pesos to one U.S. dollar and other transactions were conducted in a free floating exchange market. On February 8, 2002, Decree 260 unified the dual exchange markets and allowed the peso to float freely with the U.S. dollar. The exchange rate at December 31, 2004, was 2.98 pesos to one U.S. dollar and the exchange rate at December 31, 2003, was 2.94 pesos to one U.S. dollar.

On February 3, 2002, Decree 214 required certain contracts that were previously payable in U.S. dollars to be payable in pesos. Pursuant to an emergency law passed on January 10, 2002, U.S. dollar obligations between private parties due after January 6, 2002, were to be liquidated in pesos at a negotiated rate of exchange which reflected a sharing of the impact of the devaluation. The Company's settlements in pesos of the existing U.S. dollar-denominated agreements were completed in 2002, thus future periods are not impacted by this mandate. This government-mandated "equitable sharing" of the impact of the devaluation resulted in a reduction in oil revenues from domestic sales in Argentina for 2002 of approximately $8 million, or $0.73 per Argentine barrel produced or $0.38 per total Company barrel produced. The Company's 2002 Argentine production costs were also reduced as a result of this mandate and the positive impact of devaluation on the Company's peso-denominated costs essentially offset the negative impact on 2002 Argentine oil revenues. Absent the January 10, 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. A $0.9 million gain resulting from the involuntary conversion was recorded in January 2002.

The Company has evaluated the effect of the economic and political events in Argentina and the Company continues to believe that the facts and circumstances indicate that the U.S. dollar remains the functional currency of its Argentine operations.

Stock Compensation

The Company has two fixed stock-based compensation plans, as more fully described in Note 3, which reserve shares of common stock for issuance to key employees and directors. Prior to 2003, the Company accounted for these plans under the recognition and measurement provisions of Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees* and related interpretations. Compensation for non-vested stock awards is recorded over the vesting periods of the awards. No stock compensation expense related to stock options granted prior to 2003 has been recognized, as all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the grant date.

Effective January 1, 2003, the Company adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, *Accounting for Stock-Based Compensation* ("SFAS 123"). The Company adopted these provisions prospectively and applied them to all employee and director awards granted, modified, or settled after January 1, 2003. Stock option awards under the Company's plans generally vest over three years, therefore, the cost related to stock compensation included in the determination of net income (loss) for 2004, 2003 and 2002 is less than that which would have been recognized if the fair value based method had been applied to all awards since the original effective date of SFAS 123. The following table illustrates the effect on net income (loss) and earnings (loss) per share if the fair value based method had been applied to all outstanding and unvested awards in each period (in thousands, except per share amounts):

	Years Ended December 31,		
	2004	2003	2002
Stock compensation expense - as reported	$ 8,941	$ 6,057	$ 1,329
Stock compensation expense - pro forma	9,056	6,716	5,796
Net income (loss) - as reported	332,592	(240,907)	(143,664)
Net income (loss) - pro forma	332,519	(241,436)	(146,889)
Income (loss) per share - as reported:			
Basic	5.11	(3.76)	(2.27)
Diluted	5.06	(3.74)	(2.26)
Income (loss) per share - pro forma:			
Basic	5.11	(3.77)	(2.32)
Diluted	5.05	(3.74)	(2.31)

Included in stock compensation expense as reported, is expense related to the Company's discontinued operations of $1.3 million, $0.8 million and $0.5 million for the years ended 2004, 2003 and 2002, respectively. The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The Company did not grant any stock options during 2004. The weighted average assumptions used for options granted in 2003 include a dividend yield of 1.6 percent, expected volatility of approximately 43.9 percent, a risk-free interest rate of approximately 2.6 percent and expected lives of 4.5 years. The weighted average assumptions used for options granted in 2002 include a dividend yield of 1.4 percent, expected volatility of approximately 50.3 percent, a risk-free interest rate of approximately 4.4 percent and expected lives of 4.5 years.

Compensation expense related to non-vested stock awards is measured based on the stock price on the date of grant of the awards. The Company accrues compensation expense over the vesting period of the non-vested stock awards. Forfeitures are recognized as a reduction of compensation expense as they occur.

Comprehensive Income (Loss)

Comprehensive income (loss) consists of the following (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Net income (loss)	$ 332,592	$ (240,907)	$ (143,664)
Foreign currency translation adjustments	16,853	92,208	4,965
Sale of Canadian operations	(89,404)	-	-
Changes in value of derivatives, net of tax	(11,019)	6,847	(11,906)
Comprehensive income (loss)	$ 249,022	$ (141,852)	$ (150,605)

The foreign currency translation adjustments shown above relate entirely to the translation of the financial statements of the Company's Canadian operating subsidiary from its functional currency (the Canadian dollar) to the Company's reporting currency (the U.S. dollar). The Canadian operations were sold in November 2004 and the cumulative translation adjustment at the date of sale was included in the gain on sale of discontinued operations.

The changes in the value of derivatives, net of tax, consist of the following (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Unrealized loss during the period	$ (19,464)	$ (5,141)	$ (15,692)
Reclassification adjustment for (gains) losses included in net income (loss)	3,185	15,692	(4,894)
	(16,279)	10,551	(20,586)
Income tax expense (benefit)	(5,260)	3,704	(8,680)
Changes in value of derivatives, net of tax	$ (11,019)	$ 6,847	$ (11,906)

The accumulated balance for each item in accumulated other comprehensive income (loss) is as follows (in thousands):

	December 31,	
	2004	2003
Foreign currency translation adjustments	$ -	$ 72,551
Changes in value of derivatives, net of tax	(13,088)	(2,069)
	$ (13,088)	$ 70,482

Approximately $13.3 million of the accumulated balance for the change in value of derivatives, net of tax at December 31, 2004, will be reclassified into net income in 2005.

Treasury Stock

Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares is reduced by the average purchase price per share of the aggregate treasury shares held.

New Accounting Pronouncements

On December 16, 2004, the FASB issued FASB Statement No. 153, *Exchanges of Nonmonetary Assets - An Amendment of APB Opinion No. 29* ("SFAS 153"). SFAS 153 amends APB Opinion No. 29 ("APB 29"), *Accounting for Monetary Transactions*, that was issued in 1973. The amendments are based on the principle that exchanges of nonmonetary assets should be measured based on the fair value of the assets exchanged. Further, the amendments eliminate the narrow exception for nonmonetary exchanges of similar productive assets and replace it with a broader exception for exchanges of nonmonetary assets that do not have "commercial substance." Previously, APB 29 required that the accounting for an exchange of a productive asset for a similar productive asset or an equivalent interest in the same or similar productive asset should be based on the recorded amount of the asset relinquished. The provisions in SFAS 153 are effective for nonmonetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Companies must apply the standard prospectively. Management does not believe the adoption of SFAS 153 will have a significant impact on the Company's financial position or results of operations.

The FASB has issued Statement of Financial Accounting Standards No. 123 (Revised 2004), *Share-Based Payment* ("SFAS 123R"). SFAS 123R requires that the compensation cost relating to share-based payment transactions be recognized in the financial statements. That cost will be measured based on the fair value of the equity or liability instruments issued. The Company will be required to apply SFAS 123R as of the first interim reporting period that begins after June 15, 2005. Management is presently evaluating the impact of SFAS 123R but does not believe the adoption of SFAS 123R will have a significant impact on the Company's financial position or results of operations.

The FASB has issued FASB Staff Position ("FSP") 109-1 and FSP 109-2 that provide accounting guidance on how companies should account for the effects of the American Jobs Creation Act of 2004 that was signed into law on October 22, 2004. The result of this legislation could affect how companies report their deferred income tax balances. The guidance in these FSP statements is effective December 21, 2004. In FSP 109-1, the FASB concludes that the tax relief (special tax deduction for domestic manufacturing) from this legislation should be accounted for as a "special deduction" instead of a tax rate reduction. Management is evaluating the impact of FSP 109-1. FSP 109-2 gives a company additional time to evaluate the effects of the legislation on any plan for reinvestment or repatriation of foreign earnings for purposes of applying Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes.*

The FASB has issued FSP 141-1 and FSP 142-1 as a result of the March 17-18, 2004, Emerging Issues Task Force ("EITF") meeting, after the EITF reached a consensus on EITF Issue No. 04-2, "Whether Mineral Rights Are Tangible or Intangible Assets," and concluded that mineral rights, as defined in the issue, are tangible assets. There was an inconsistency between this consensus and the characterization of mineral rights as intangible assets in SFAS 141 and SFAS 142. Accordingly, this FSP amended SFAS 141 and SFAS 142 in order to address that inconsistency. The guidance in this FSP was applicable to the first reporting period beginning after April 29, 2004. The adoption of this FSP had no impact on the Company's financial position.

2. Long-term Debt

Long-term debt at December 31, 2004 and 2003, consisted of the following (in thousands):

	December 31, 2004	December 31, 2003
Secured Debt -		
Revolving credit facility	$ -	$ -
Unsecured Debt -		
8 1/4% Senior Notes due 2012	350,000	350,000
Senior subordinated notes:		
9 3/4% Notes due 2009	-	150,000
7 7/8% Notes due 2011, less unamortized discount	199,949	199,943
	$ 549,949	$ 699,943

Revolving Credit Facility

The Company has available a senior secured revolving credit facility under a credit agreement, as amended, with certain banks (the "Bank Facility"). The Bank Facility establishes a borrowing base ($325 million at December 31, 2004) 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 $300 million. The next borrowing base determination will be in April 2005. At December 31, 2004, the unused availability under the Bank Facility (considering outstanding letters of credit of approximately $3.6 million) was approximately $296.4 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 therein) 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 secured debt to the borrowing base. In addition, the Company must pay a commitment fee ranging from 0.375 to 0.50 percent per annum (based on the ratio of the outstanding senior secured debt to the borrowing base) on the unused portion of the banks' commitment. There were no outstanding advances under the Bank Facility at December 31, 2004.

The Company's borrowing base is redetermined on a semi-annual basis by the banks based on their review of the Company's oil and gas reserves. If the sum of outstanding senior secured debt exceeds the borrowing base, as redetermined, the Company must repay such excess. Any principal advances outstanding are due at maturity on May 2, 2008. The Bank Facility is secured by a first priority lien on the Company's U.S. oil and gas properties, constituting at least 80 percent of the present value of the Company's U.S. proved reserves owned now or in the future. The Bank Facility will be guaranteed by any of the Company's existing and future U.S. subsidiaries that grant a lien on oil and gas properties under the Bank Facility.

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 therein) and a minimum tangible net worth (as defined therein). The Company was in compliance with all of the covenants under the Bank Facility at December 31, 2004.

In conjunction with the elimination of the Company's previously existing revolving credit facility and the partial redemption of the 9% Senior Subordinated Notes due 2005 (the "9% Notes") in May 2002, the Company was required to expense certain associated deferred financing costs and discounts. This $5.2 million non-cash charge, along with a $3.0 million cash charge for the call premium on the 9% Notes, resulted in a one-time charge of approximately $8.2 million ($5.0 million net of tax) in the second quarter of 2002.

Senior Notes

On May 2, 2002, the Company issued, through a Rule 144A offering, $350 million of its 8 1/4% Senior Notes due 2012 (the "8 1/4% Notes"). All of the net proceeds were used to repay a portion of the outstanding balance under the Company's revolving credit facility and to redeem $100 million of the Company's then outstanding 9% Notes. The 8 1/4% Notes are redeemable at the option of the Company, in whole or in part, at any time on or after May 1, 2007. In addition, on or before May 1, 2005, the Company may redeem up to 35 percent of the 8 1/4% Notes with the proceeds of certain underwritten public offerings of the Company's common stock. The 8 1/4% Notes mature on May 1, 2012, with interest payable semi-annually on May 1 and November 1 of each year.

Upon a change in control of the Company (as defined in the applicable indentures), holders of the 8 1/4% Notes and the Company's senior subordinated notes (collectively, 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. The Company was in compliance with all of the covenants under the bond indentures at December 31, 2004.

Senior Subordinated Notes

On December 20, 1995, the Company issued $150 million of its 9% Notes. The 9% Notes were redeemable at the option of the Company, in whole or in part, at any time on or after December 15, 2000. In May 2002, the Company redeemed $100 million of the 9% Notes and redeemed the remaining $50 million of the 9% Notes in March 2003. In conjunction with the redemption of the remaining 9% Notes, the Company was required to expense certain associated deferred financing costs and discounts. This $0.7 million non-cash charge, along with a $0.7 million cash charge for the call premium on the 9% Notes, resulted in a one-time charge of approximately $1.4 million ($0.9 million net of tax), in the first quarter of 2003.

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 were redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2002. In October 2003, the Company redeemed the entire $100 million principal balance of the 8 5/8% Notes due 2009 with cash provided by advances under the revolving credit facility. As a result, the Company was required to expense certain associated deferred financing costs and discounts. This $2.3 million non-cash charge and a $3.2 million cash charge for the call premium resulted in a one-time charge of approximately $5.5 million ($3.4 million net of tax) in the fourth quarter of 2003.

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 were redeemable at the option of the Company, in whole or in part, at any time on or after February 1, 2004. In February 2004, the Company redeemed the entire $150 million principal balance of the 9 3/4% Notes due 2009 with cash provided by advances under the revolving credit facility. As a result, the Company was required to expense certain associated deferred financing costs. The $2.6 million non-cash charge and a $7.3 million cash charge for the call premium resulted in a one-time charge of approximately $9.9 million ($6.0 million net of tax) that the Company recorded in the first quarter of 2004.

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. The 7 7/8% Notes mature on May 15, 2011, with interest payable semi-annually 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 revolving credit facility. The 7 7/8% Notes are unsecured senior subordinated obligations of the Company and rank subordinate in right of payment to all senior indebtedness (as defined).

3. Capital Stock

Stock Plans

The Company has two fixed stock-based compensation plans. 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) non-vested stock and non-vested stock rights (collectively, "non-vested stock awards"). As of December 31, 2004, awards for a total of 4,241,851 shares of common stock remain available for grant under the 1990 Plan.

The 1990 Plan is administered by the compensation committee of the Company's Board of Directors (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. Non-vested 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. Non-vested stock rights under the 1990 Plan will generally represent the right to receive shares of common stock when certain restrictions established by the Board lapse.

Under the Non-Management Director Stock Option Plan (the "Director Plan"), 60,000 shares of common stock were available for issuance to the outside directors of the Company. As of December 31, 2004, options for a total of 51,000 shares of common stock had been granted under the Director Plan. Options granted pursuant to the Director Plan are non-qualified stock options with terms of 10 years and an option exercise price equal to the fair market value of the common stock on the date of grant. Under the terms of the Director Plan, no additional options can be granted under this plan.

The following is an analysis of all option activity under the 1990 Plan and the Director Plan for 2004, 2003 and 2002:

	Years Ended December 31,					
	2004		2003		2002	
	Shares	Wtd. Avg. Exercise Price	Shares	Wtd. Avg. Exercise Price	Shares	Wtd. Avg. Exercise Price
Beginning stock options outstanding	2,985,936	$10.37	5,440,736	$14.42	5,715,186	$14.57
Stock options granted	-	-	55,000	10.19	77,000	11.47
Stock options canceled	-	-	(2,333,500)	19.96	(270,450)	18.94
Stock options exercised	(1,472,636)	9.59	(176,300)	8.30	(81,000)	7.31
Ending stock options outstanding	1,513,300	$11.12	2,985,936	$10.37	5,440,736	$14.42
Ending stock options exercisable	1,483,300	$11.13	2,878,271	$10.30	3,894,071	$12.18
Weighted average SFAS 123 fair value of options granted	$ -		$ 3.53		$ 4.80	

Of the 1,513,300 options outstanding at December 31, 2004: (a) 932,000 options have exercise prices between $7.25 and $12.78, with a weighted average exercise price of $8.28 and a weighted average contractual life of 3.6 years (902,000 of these options are currently exercisable at a weighted average price of $8.20); and (b) 581,300 options have exercise prices between $15.50 and $22.94, with a weighted average exercise price of $15.67 and a weighted average contractual life of 2.2 years (all of these options are currently exercisable).

All of the outstanding options are exercisable at various times in years 2005 through 2012. 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 non-vested stock awards under the 1990 Plan. The outstanding non-vested stock awards generally vest over a one-to-three-year period except for 200,000 shares of non-vested stock granted to certain senior executives of the Company in 2003 at a time when the Company's stock price was $11.42 per share. These non-vested shares would vest when the Company's stock price had closed at $15.00 per share or higher for 45 consecutive trading days. These non-vested stock awards vested in 2004. In addition, the Company granted 134,000 non-vested stock rights in 2004, which vest over a three-year period with the number of final shares to be issued based on the achievement of certain performance criteria tied to the Company's publicly traded share price performance relative to a group of peer companies. The final shares issued will range from zero shares to 200 percent of the initial rights granted.

Non-vested stock award compensation expense (based on the stock price on the date of grant), is being amortized over the vesting periods. During 2004, 2003 and 2002, the Company recorded non-vested stock award compensation expense, including expense related to discontinued operations, of $8.6 million, $5.9 million and $1.2 million, respectively. Stock compensation expense is reduced when non-vested stock awards are forfeited. The following is an analysis of all non-vested stock awards under the 1990 Plan for 2004, 2003 and 2002:

	Years Ended December 31,		
	2004	2003	2002
Beginning non-vested stock awards outstanding	1,353,352	390,784	110,000
Non-vested stock awards granted	354,690	1,215,303	416,650
Non-vested stock awards canceled	(22,459)	(134,713)	(119,200)
Non-vested stock awards vested	(839,509)	(118,022)	(16,666)
Ending non-vested stock awards outstanding	846,074	1,353,352	390,784

On February 20, 2003, pursuant to the terms of an offer to exchange, the Company accepted for exchange options to purchase 2,118,000 shares of its common stock (included in the total 2,333,500 stock options canceled in 2003), representing approximately 95.1 percent of the 2,227,500 options that were eligible to be tendered in the offer. The options exchanged had exercise prices ranging from $19.28 to $21.81 per share. In accordance with the terms of the offer to exchange, the Company granted non-vested stock awards representing an aggregate of 562,840 shares of its common stock (included in the total 1,215,303 non-vested stock awards granted in 2003) in exchange for the tendered options.

At December 31, 2004, a total of 5,904,818 shares of the Company's common stock are reserved for issuance pursuant to the 1990 Plan and the Director Plan.

In March 2004, the Company entered into a separation agreement with a former executive under which the Company extended the period in which the former executive could exercise each outstanding vested stock option granted to him under the 1990 Stock Plan to the end of the term of such option. Pursuant to the terms of the non-vested stock award agreements for the shares of non-vested stock granted to the Company's former executive under the 1990 Stock Plan, such shares vested in full as of the date of his termination of employment. As a result, the Company recorded non-cash stock compensation expense of approximately $2.2 million in the first quarter of 2004.

Preferred Stock

Preferred stock at December 31, 2004, 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.

Preferred Share Purchase Rights

On March 16, 1999, the Board adopted a stockholder rights plan and declared a dividend distribution of one Preferred Share Purchase Right (a "Right") on each outstanding share of the Company's common stock to stockholders of record on April 5, 1999 (the "Record Date"). Each common share issued after the Record Date has also been issued a Right. The description and terms of the Rights are set forth in the Rights Agreement dated March 16, 1999, between the Company and the rights agent. The Rights will expire on April 5, 2009.

On April 3, 2002, the Company and the rights agent executed the First Amendment to Rights Agreement (the "Amendment"). As more fully set forth in the Amendment, the Amendment, among other things, amends the Rights Agreement to lower the threshold at which a person becomes an Acquiring Person (as defined in the Rights Agreement, as amended by the Amendment) and lowers the percentage at which the rights plan is triggered from 15 percent to 10 percent.

The Rights will be exercisable only if a person or group acquires 10 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 10 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 10 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 10 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 10 percent or more of the Company's common stock, the Rights are redeemable for $0.01 per Right at the option of the Board.

Treasury Stock

In 2003 and 2004, certain members of management repaid indebtedness to the Company through cash payments and through the sale of shares of the Company's common stock to the Company at the market price of the Company's common stock on the date of the repayment.

4. Commitments and Contingencies

The Company had $3.6 million in letters of credit outstanding at December 31, 2004. These letters of credit relate primarily to bonding requirements of various state regulatory agencies in the U.S. for oil and gas operations. The Company's availability under its revolving credit facility is reduced by the outstanding letters of credit.

Rent expense was $2.0 million, $2.7 million and $2.4 million for 2004, 2003 and 2002, respectively. The future minimum commitments under long-term, non-cancelable leases for office space are $2.4 million, $2.4 million and $3.8 million for the years 2005 through 2007, respectively. There are no future minimum commitments under non-cancellable leases after 2007.

The Company has entered into certain firm gas transportation and compression agreements in Bolivia whereby the Company has committed to transport and compress certain volumes of gas at established government-regulated fees. While these fees are not fixed, they are government-regulated and therefore, the Company believes the risk of significant fluctuations is minimal. The Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to utilize all of the contracted transportation and compression capacity under these arrangements. The Company paid $2.6 million, $2.5 million and $2.4 million under these agreements in 2004, 2003 and 2002, respectively. Based on the current fee level, these commitments total approximately $1.2 million in 2005, $1.3 million in 2006 and $0.3 million in each of the years 2007, 2008 and 2009.

The Company has future minimum long-term electric power purchase commitments in Argentina of $3.6 million in 2005, $3.6 million in 2006 and $4.9 million in 2007. The Company paid $2.8 million under these agreements in 2004.

The Company has also entered into "deliver-or-pay" arrangements where it has committed to deliver certain volumes of gas to third parties in Bolivia and Argentina for a specified period of time. These volumes will be sold at market prices. If the required volumes are not delivered, the Company must pay for the undelivered volumes at the then-current market price. Similar to the firm transportation and compression agreements, the Company entered into these arrangements to ensure its access to gas markets and the Company currently expects to produce sufficient volumes to satisfy all of its deliver-or-pay obligations. The volumes contracted under the agreement in Bolivia are 7.1 Bcf in 2005, 7.0 Bcf in 2006, 6.0 Bcf in 2007, 6.9 Bcf in 2008 and 6.9 Bcf in 2009. The volumes contracted under the agreement in Argentina are 6.1 Bcf in 2005, 3.3 Bcf in 2006, 3.6 Bcf in 2007 and 4.0 Bcf in 2008. The Company made no payments under these agreements in 2004, 2003 or 2002.

On November 5, 2004, the Company received a letter from the Ministry of Economy of the Argentina Province of Santa Cruz requesting that royalty payments made since March 2002 be amended to eliminate the market impact of the Argentina export tax on sales to domestic refiners. The Company believes this request is made without merit, as royalties are calculated and paid on the actual prices received from third party purchasers.

On December 22, 2004, the Compensation Committee of the Company's Board of Directors established a performance-based cash bonus program for the Company's Chairman of the Board, President and Chief Executive Officer (the "Bonus Program") to provide him with added incentive to enhance stockholder value by achieving certain specific performance goals. Under the Bonus Program, he has the ability to earn a cash bonus in the amount of zero to $2.4 million, based on the achievement of certain performance criteria tied to the Company's publicly traded share price performance relative to a group of peer companies.

Under the terms of the Company's concession agreement in Yemen, the Company is required to make annual payments of $337,500 throughout the 20-year term of the agreement, which was granted in October 2003.

The Company is a named 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, while the outcome of such lawsuits or proceedings cannot be predicted with certainty, the likelihood of a material adverse effect on the Company's financial position or results of operations resulting from the resolution of such legal proceedings is remote.

5. Financial Instruments

Price Risk Management

The Company periodically uses derivative financial instruments to reduce the impact of oil and gas price fluctuations on its operating results and cash flows and generally attempts to qualify such derivatives as hedges for accounting purposes. The Company has historically used price swap agreements and basis swap agreements to conduct its price risk management activities, but may also consider using options (including caps and floors), futures and forward contracts. The price 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 derivative activities are conducted with 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 derivative transactions to those with counterparties with appropriate credit standings. During 2004, a substantial portion of the Company's derivative financial instruments ceased to qualify for hedge accounting due to significant oil price fluctuations.

During 2002, the Company participated in oil price swap agreements covering 4.9 MMBbls of 2002 oil production at a weighted average NYMEX reference price of $25.16 per Bbl and gas price swap agreements covering 11.3 million MMBtu of 2002 gas production. The U.S. portion of the gas price swap agreements (5.2 million MMBtu) was at a NYMEX reference price of $2.72 per MMBtu. The Canadian portion of the gas price swap agreements (6.1 million MMBtu) was at the AECO gas price index reference price of 3.67 Canadian dollars per MMBtu and was settled in Canadian dollars. Additionally, the Company entered into gas price collar arrangements for 2.2 million MMBtu of its U.S. gas production in 2002 with floor NYMEX reference prices of $3.50 per MMBtu and cap NYMEX reference prices ranging from $4.00 to $5.10 per MMBtu. In conjunction with each of the 2002 U.S. gas price swap agreements and gas price collar agreements, the Company entered into basis swap agreements covering identical periods of time and volumes. These basis swaps established a differential between the NYMEX reference price and the various delivery points at levels that are comparable to the historical differentials the Company has received. All of these 2002 transactions were accounted for as cash flow hedges under the terms of SFAS 133.

During 2003, the Company participated in oil price swap agreements covering 4.9 MMBbls of 2003 oil production and gas price swap agreements covering 20.1 million MMBtu of 2003 gas production. The U.S. portion of the oil price swap agreements (4.7 MMBbls) was at a weighted average NYMEX reference price of $26.79 per Bbl. The Canadian portion of the oil price swap agreements (0.2 MMBbls) was at a weighted average NYMEX reference price of 43.19 Canadian dollars per Bbl and was settled in Canadian dollars. The U.S. portion of the gas price swap agreements (11.0 million MMBtu) was at a weighted average NYMEX reference price of $4.00 per MMBtu. The Canadian portion of the gas price swap agreements (9.1 million MMBtu) was at a weighted average NYMEX reference price of 6.63 Canadian dollars per MMBtu and was settled in Canadian dollars. The Company also entered into basis swap agreements for approximately 8.4 million MMBtu of its 2003 U.S. gas production covered by the gas price swap agreements.

Beginning October 26, 2003, a portion of the Company's oil and gas production in Ventura County, California was shut-in as a result of fires in the area. The Company had designated oil sales from this area as hedged transactions for the first three months of 2004. Although oil and gas production in this area is increasing as repairs are made, at December 31, 2003, the Company determined that the occurrence of the forecasted transaction in the hedges was no longer probable for the first three months of 2004. Accordingly, at December 31, 2003, the Company reclassified approximately $0.9 million of derivative losses from accumulated other comprehensive income to "Derivative losses" in the accompanying statements of operations. The Company did not discontinue any other hedges in 2003 because of the probability that the original forecasted transaction would not occur. All other derivative transactions in 2003 were accounted for as cash flow hedges under the terms of SFAS 133.

During 2004, the Company participated in oil price swap agreements covering 5.6 MMBbls of 2004 oil production and at a weighted average NYMEX reference price of $30.10 per Bbl and gas price swap agreements covering 21.8 million MMBtu of 2004 gas production at a weighted average NYMEX reference price of $5.92 per MMBtu. In conjunction with each of the 2004 U.S. gas price swap agreements, the Company entered into basis swap agreements covering identical periods of time and volumes.

In September 2004, the differential between NYMEX crude oil index prices and certain U.S. crude oil postings widened. This market fluctuation caused the Company to conclude that certain of its crude oil hedges were no longer highly effective in achieving offsetting changes in the cash flows of the physical transactions. In accordance with SFAS 133, the Company discontinued hedge accounting for these contracts in September and recorded the changes in the fair value of these contracts as non-operating expense.

At December 31, 2004, the Company had entered into oil price swap agreements for 5.0 MMBbls of 2005 oil production at a weighted average NYMEX reference price of $36.17 per Bbl, 1.7 MMBbls of 2006 oil production at a weighted average NYMEX reference price of $36.60 per Bbl, and 0.4 MMBbls of 2007 oil production at a weighted average NYMEX reference price of $36.85 per Bbl. At December 31, 2004, the Company had also entered into gas price swap agreements for a 4.7 million MMBtu of 2005 gas production at a weighted average NYMEX reference price of $6.33 per MMBtu, 1.0 million MMBtu of 2006 gas production at a weighted average NYMEX reference price of $6.47 per MMBtu, and 0.9 million MMBtu of 2007 gas production at a weighted average NYMEX reference price of $6.00 per MMBtu, along with gas price collar agreements for a total of 11.0 million MMBtu of 2005 gas production with NYMEX floor reference prices of $6.00 per MMBtu and NYMEX cap reference prices ranging from $6.80 to $9.21 per MMBtu. Additionally, the Company has entered into basis swap agreements for volumes and periods of time that coincide with each of the gas price swap agreements and gas price collar agreements for 2005, 2006 and 2007. All of the gas price swap agreements, gas price collar agreements and basis swap agreements continued to qualify as cash flow hedges at December 31, 2004. Oil price swap agreements covering 1.6 MMBbls of 2005 oil production at a weighted average NYMEX reference price of $27.22 continued to be accounted for as cash flow hedges under the terms of SFAS 133 at December 31, 2004. All of the other oil price swap agreements in place at December 31, 2004, were accounted for under mark-to-market accounting.

The Company continues to monitor the correlation between the changes in NYMEX crude oil index prices and the changes in U.S. crude oil postings. As of March 1, 2005, the Company has determined that the correlation indicates that its existing oil price swap agreements will again be highly effective in achieving offsetting changes in the cash flows of the physical transactions and, accordingly, has redesignated all of the oil price swap contracts as cash flow hedges and will resume hedge accounting for these contracts as of March 1, 2005. The Company has not entered into any new oil or gas price swap agreements or collars since December 31, 2004.

The Company continues to monitor oil and gas prices and may enter into additional derivative transactions in the future.

The Company records the fair value of its commodity swap agreements as a current or long-term asset or liability based on the period in which the forecasted transaction will occur. The fair value of the derivative financial instrument obligation at December 31, 2004 and 2003 consisted of the following (in thousands):

	December 31,	
	2004	2003
Current liability	$ 27,672	$ 7,551
Long-term liability	6,774	-
Liability of discontinued operations	-	325
Total	$ 34,446	$ 7,876

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, 2004 and 2003, was $598.9 million and $749.5 million, respectively, compared with carrying values of $549.9 million and $700.0 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, 2004 and 2003, the Company would have paid approximately $34.4 million and $7.9 million, respectively, to terminate its swap agreements then in place. The carrying value of other financial instruments approximates fair value because of the short maturity of those instruments.

6. Income Taxes

Income (loss) from continuing operations before income taxes and cumulative effect of changes in accounting principles is composed of the following (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Domestic	$ 27,610	$ (22,033)	$ (51,415)
Foreign	167,320	123,381	101,120
	$ 194,930	$ 101,348	$ 49,705

The total provision (benefit) for income taxes, excluding amounts related to the Company's discontinued operations in Trinidad, Ecuador and Canada, consists of the following (in thousands):

	Years Ended December 31,		
	2004	2003	2002
Current:			
Domestic	$ (2,329)	$ (9,789)	$ (13,826)
Foreign	60,235	49,929	29,834
Deferred:			
Domestic	5,804	(3,389)	93
Foreign	5,779	5,103	(1,367)
	$ 69,489	$ 41,854	$ 14,734

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

	Years Ended December 31,		
	2004	2003	2002
U.S. federal statutory income tax rate	35.0%	35.0%	35.0%
State income tax	0.6	(0.8)	(4.0)
Foreign operations	3.7	7.4	(7.4)
Other	(3.6)	(0.3)	6.0
	35.7%	41.3%	29.6%

The components of the Company's net deferred tax liability, excluding amounts related to the Company's discontinued operations in Trinidad, Ecuador and Canada as of December 31, 2004 and 2003, are as follows (in thousands):

	December 31,	
	2004	2003
Deferred Tax Assets:		
Book-tax differences in property basis	$ 13,987	$ 15,454
U.S. federal and state net operating loss carryforwards	9,893	2,255
U.S. capital loss carryforward	82,510	-
Foreign net operating loss carryforwards	9,747	11,759
Other temporary book-tax differences	21,872	7,750
	138,009	37,218
Less: Valuation allowances	(88,653)	-
	49,356	37,218
Deferred Tax Liabilities:		
Book-tax differences in property basis	97,559	75,382
Other temporary book-tax differences	3,616	3,070
	101,175	78,452
Net deferred tax liability	$ 51,819	$ 41,234

The Company expects to generate a U.S. federal regular income tax net operating loss ("NOL") for 2004, which it can carry back against taxable income in prior years, receiving a refund of taxes previously paid. The Company has no U.S. Federal NOL carryforward as of December 31, 2004; however, the Company does have 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. The Company has recorded a $6.1 million valuation allowance against certain state NOL carryforward benefits that it does not expect to realize due to carryforward period limitations.

The Company generated a capital loss for U.S. income tax purposes during 2004 related to the transfer and sale of its Canadian operations. Of the $323.4 million capital loss generated, $87.7 million can be carried back to prior years against previously reported capital gains. The Company has recorded a $30.7 million tax receivable related to this carryback. The remaining $235.7 million of capital loss can be carried forward up to 5 years and is available to offset any future capital gains generated in the U.S. during this time. As the Company does not currently have plans for the disposal of any assets that might generate capital gains, it has recorded a valuation allowance against the full amount ($82.5 million) of the deferred tax asset related to this carryforward in its financial statements.

Earnings of the Company's foreign subsidiaries are subject to foreign income taxes. At December 31, 2004, unremitted earnings of subsidiaries outside of the United States were approximately $425 million, on which no United States taxes had been provided, as it is the Company's intention, generally, to invest these earnings permanently or to repatriate the earnings only when possible to do so at minimal additional tax cost. The Company has paid or accrued foreign income taxes of approximately $230 million related to these earnings which may be available as a credit against U.S. federal income taxes on such income, if distributed. It is not practicable to estimate the amount of additional tax that might be payable on this foreign income if distributed because the amount of foreign taxes eligible for credit against U.S. federal income taxes on any such distribution will be determined based on facts and circumstances at the time of any actual distribution. The Company recorded additional U.S. income taxes of $19.4 million in 2003 related to the repatriation of previously untaxed foreign earnings as a result of the sale of its interest in Ecuador in January 2003.

The American Jobs Creation Act of 2004 (the "Jobs Act") introduced a special one-time dividends-received deduction on the repatriation of certain foreign earnings to the United States, provided certain conditions are met. If certain conditions are met, a 5.25 percent effective income tax rate would apply to eligible repatriations of certain foreign earnings. The Company is currently evaluating these provisions under the Jobs Act and is also awaiting interpretive guidance relating to these regulations from either Congress or the Treasury Department. At the current date, the Company has not determined that it will repatriate any unremitted foreign earnings under the special one-time repatriation provisions of the Jobs Act. However, the Company continues to evaluate the special one-time repatriation provisions of the Jobs Act and that evaluation could result in the Company repatriating certain unremitted foreign earnings. The amount of unremitted foreign earnings that the Company is evaluating for repatriation, including projected 2005 earnings, ranges from zero to $500 million. The Company expects to complete its evaluation of the amount of repatriation, if any, during 2005. If the Company was to repatriate certain unremitted foreign earnings under the special one-time repatriation provisions of the Jobs Act in the range noted in the preceding sentence, the income tax effects of such repatriation could range from zero to approximately $26 million.

The Company has a Bolivian income tax NOL carryforward of approximately $39.0 million that does not expire. The Company has also incurred approximately $80 million related to its Yemen operations that it expects to recover in the future under the cost recovery provisions of its production sharing agreement with the government of Yemen. These provisions allow the Company to annually offset a portion of its revenues that would otherwise be taxable with costs previously incurred in Yemen until such costs have been fully recovered. The Company expects to recover this amount within the next five years.

7. Discontinued Operations

On July 30, 2002, the Company completed the sale of its operations in Trinidad. The Company received $40 million in cash and recorded a gain of approximately $31.9 million ($14.9 million after income taxes). On January 31, 2003, the Company completed the sale of its operations in Ecuador. The Company received $137.4 million in cash and recorded a gain of approximately $47.3 million ($9.5 million after income taxes). On November 30, 2004, the Company completed the sale of its operations in Canada. The Company received $274.7 million in cash and recorded a gain of approximately $167.8 million ($198.5 million including income tax benefit).

In accordance with the rules established by Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS 144"), the Company's operations in Trinidad, Ecuador and Canada, along with the gains on the sales of the operations in Trinidad, Ecuador and Canada are accounted for as discontinued operations in the accompanying consolidated financial statements.

Following is summarized financial information for the Company's operations in Trinidad, Ecuador and Canada (in thousands):

TRINIDAD	Year Ended December 31, 2002
Revenues	$ -
Pre-tax loss from discontinued operations	$ (711)
Deferred tax benefit	(253)
Loss from discontinued operations before gain on sale	(458)
Gain on sale of operations, net of $16,939 income tax expense	14,943
Income from discontinued operations, net of tax	$ 14,485

ECUADOR	Years Ended December 31, 2003	2002
Revenues	$ 3,074	$ 24,153
Pre-tax income from discontinued operations	$ 1,812	$ 10,113
Deferred tax expense	459	2,493
Income from discontinued operations before gain on sale	1,353	7,620
Gain on sale of operations, net of $37,766 income tax expense	9,491	-
Income from discontinued operations, net of tax	$ 10,844	$ 7,620

The income tax expense related to the gain on the sale of the Company's operations in Ecuador includes $19.4 million of taxes on previously unremitted foreign earnings. No U.S. income taxes were previously recorded on these earnings.

CANADA	Years Ended December 31, 2004	2003	2002
Revenues	$ 93,110	$ 119,077	$ 113,808
Pre-tax income (loss) from discontinued operations	$ 8,672	$ (431,725)	$ (194,015)
Income tax benefit	(21)	(113,361)	(53,822)
Income (loss) from discontinued operations before gain on sale	8,693	(318,364)	(140,193)
Gain on sale of operations, including $30,701 income tax benefit	198,458	-	-
Income (loss) from discontinued operations, net of tax	$ 207,151	$ (318,364)	$ (140,193)

	Year Ended December 31, 2003
Current assets	$ 40,799
Property, plant and equipment, net	177,683
Other assets, net	5,839
Assets of discontinued operations	$ 224,321
Current liabilities	$ 30,368
Long-term liability for asset retirement obligations	16,918
Liabilities of discontinued operations	$ 47,286

All of the Company's goodwill was related to the Company's Canadian operations and represented the excess of the purchase price over the estimated fair value of the net assets acquired in the purchase of Genesis in 2001. Effective January 1, 2002, the Company adopted the provisions of SFAS 142. SFAS 142 changed the accounting for goodwill from an amortization method to an impairment assessment only method.

As required by SFAS 142, the initial impairment assessment was made by comparing the fair value of the Canadian operations, as determined in accordance with SFAS 142, to its book value. The Company completed its initial assessment in the second quarter of 2002 and recorded a non-cash charge of $60.5 million as a cumulative effect of change in accounting principle retroactive to January 1, 2002, in accordance with the provisions of SFAS 142. The Company performed assessments of goodwill for impairment as of December 31, 2003 and 2002, and recorded additional non-cash charges of $25.7 million and $76.4 million in 2003 and 2002, respectively, which are now included in income (loss) from discontinued operations. Certain downward revisions recorded to the Company's Canadian oil and gas reserves in the fourth quarters of 2003, 2002 and 2001 and decreases in oil and gas price expectations from the May 2, 2001, acquisition of Genesis to January 1, 2002, were the primary factors which led to the goodwill impairments.

The Company engaged an independent appraisal firm to determine the fair value of its Canadian reporting unit as of January 1, 2002, and December 31, 2002. These fair value determinations were made principally on the basis of present value of future after tax cash flows, although other valuation methods were considered. The book value of the Canadian operations exceeded the fair value determined by the independent appraisal firm, indicating a possible impairment of goodwill. The Company then calculated the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the Canadian operations from the fair value of the Canadian operations determined in step one of the assessment. The carrying value of the goodwill exceeded this calculated implied fair value of the goodwill at January 1, 2002, and at December 31, 2002, resulting in the impairment charges. As a result of the significant impairments of the Company's Canadian oil and gas properties in the fourth quarter of 2003, the Company determined that goodwill was fully impaired at December 31, 2003.

The changes in the carrying amount of goodwill for the years ended December 31, 2004, 2003 and 2002, were as follows (in thousands):

December 31, 2001	$ 156,990
Impairment on adoption of SFAS 142	(60,547)
Impairments	(76,351)
Change in foreign currency exchange rate	1,007
December 31, 2002	21,099
Impairments	(25,673)
Change in foreign currency exchange rate	4,574
December 31, 2003 and 2004	$ -

8. Detail of Other Payables and Accrued Liabilities

(In thousands)	December 31, 2004	December 31, 2003
Accrued oil and gas capital expenditures	$ 24,047	$ 10,785
Accrued production, ad valorem and export taxes	9,026	2,571
Accrued general and administrative expenses	8,314	3,957
Accrued production costs	7,725	7,363
Accrued interest payable	6,939	7,360
Current liability for asset retirement obligations	2,359	4,760
Other	15,338	24,711
	$ 73,748	$ 61,507

9. 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 crude oil, condensate, natural gas liquids and natural gas. The gas marketing segment generates a margin through the purchase and resale of both Company-produced and third party-produced gas volumes. The Company evaluates the performance of its operating segments based on operating income.

The Company previously reported its gathering and plant operations as a separate business segment. Due to changes in the Company's internal organization, as of January 1, 2004, the gathering and plant operations are now considered to be part of the Company's United States exploration and production business segment. Information for 2003 and 2002 has been reclassified to conform to this presentation.

Operations in the gas marketing segment 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 Bulgaria. The financial information related to the Company's discontinued operations in Trinidad, Ecuador and Canada has been excluded for all periods presented (see Note 7). Summarized financial information for the Company's reportable segments is shown on the following pages.

2004 (in thousands)	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
External segment revenues	$ 350,565	$ 319,985	$ 15,908	$ 20,246	$ -
Intersegment revenues	-	-	-	-	-
Depreciation, depletion and amortization expense	52,041	43,671	3,277	1,861	-
Impairment of proved oil and gas properties	6,049	-	-	-	-
Operating income (loss)	155,782	160,643	5,314	11,306	(5,980)
Total assets	661,096	621,847	115,947	76,424	36
Capital investments	181,028	128,158	-	33,696	5,292
Long-lived assets	559,596	570,550	88,689	52,415	-

2004 (in thousands)	Gas Marketing	Corporate	Total
External segment revenues	$ 71,476	$ -	$ 778,180
Intersegment revenues	2,955	-	2,955
Depreciation, depletion and amortization expense	-	2,352	103,202
Impairment of proved oil and gas properties	-	-	6,049
Operating income (loss)	4,207	(53,165)	278,107
Total assets	23,743	145,799	1,644,892
Capital investments	-	2,234	350,408
Long-lived assets	-	5,128	1,276,378

2003 (in thousands)	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
External segment revenues	$ 253,507	$ 276,132	$ 14,475	$ -	$ -
Intersegment revenues	-	-	-	-	-
Depreciation, depletion and amortization expense	39,473	43,518	2,815	-	-
Impairment of proved oil and gas properties	6,050	-	-	-	-
Operating income (loss)	93,598	142,620	2,662	(4,735)	(1,776)
Total assets	478,468	540,907	117,648	23,871	1,389
Capital investments	76,944	58,332	1,653	12,370	2,536
Long-lived assets	443,793	491,122	91,438	23,628	847

2003 (in thousands)	Gas Marketing	Corporate	Total
External segment revenues	$ 70,633	$ -	$ 614,747
Intersegment revenues	1,199	-	1,199
Depreciation, depletion and amortization expense	-	2,008	87,814
Impairment of proved oil and gas properties	-	-	6,050
Operating income (loss)	2,586	(48,209)	186,746
Total assets	10,712	56,943	1,229,938
Capital investments	-	1,789	153,624
Long-lived assets	-	5,383	1,056,211

2002 (in thousands)	Exploration and Production				
	U.S.	Argentina	Bolivia	Yemen	Other Foreign
External segment revenues	$ 219,455	$ 232,787	$ 12,344	$ -	$ -
Intersegment revenues	-	-	-	-	-
Depreciation, depletion and amortization expense	52,712	46,067	3,564	-	-
Impairment of proved oil and gas properties	16,972	-	-	-	-
Operating income (loss)	43,904	117,460	2,070	(12,215)	(46)
Total assets	427,555	497,540	119,239	16,452	190
Capital investments	34,040	19,008	2,625	7,686	100
Long-lived assets	395,487	448,812	92,585	15,897	88

2002 (in thousands)	Gas Marketing	Corporate	Total
External segment revenues	$ 54,392	$ -	$ 518,978
Intersegment revenues	902	-	902
Depreciation, depletion and amortization expense	-	2,529	104,872
Impairment of proved oil and gas properties	-	-	16,972
Operating income (loss)	1,736	(36,158)	116,751
Total assets	11,260	39,792	1,112,028
Capital investments	-	-	63,459
Long-lived assets	-	4,979	957,848

Intersegment sales are priced in accordance with terms of existing contracts and current market conditions. Capital investments include expensed exploratory costs. Amounts below the "operating income" line on the statements of operations are not allocated to segments. General and administrative expense and stock compensation are included in the corporate segment, except for certain operating expenses related to oil and gas producing activities, which are allocated to each exploration and production segment. Operating income (loss) includes the cumulative effect of changes in accounting principles, net of tax.

During 2004, sales to two crude oil purchasers of the exploration and production segment represented approximately 21 percent and 15 percent, respectively, of the Company's total revenues. During 2003, sales to two crude oil purchasers of the exploration and production segment represented approximately 21 percent and 10 percent of the Company's total revenues from continuing operations. During 2002, sales to two crude oil purchasers of the exploration and production segment represented approximately 25 percent and 10 percent, respectively, of the Company's total revenues from continuing operations.

10. Quarterly Results (Unaudited)

The following is a summary of the quarterly results of operations for the years ended December 31, 2004 and 2003. All of the quarters for 2004 and 2003 have been restated to exclude the Company's discontinued operations in Trinidad, Ecuador and Canada, except income (loss) before cumulative effect of change in accounting principle and net income (loss) and the respective per share amounts (see Note 7).

(In thousands, except per share amounts)	Quarter Ended			
	Mar. 31	Jun. 30	Sept. 30	Dec. 31
2004				
Revenues	$ 163,744	$ 178,269	$ 203,671	$ 232,496
Operating income	56,379(a)	63,173	74,181	84,374(a)
Provision for income taxes	11,878(a)	18,626	18,725	20,260(a)
Net income	19,135(a)	37,409	27,015	249,033(a,b)
Net income per share:				
Basic	0.30(a)	0.58	0.41	3.78(a,b)
Diluted	0.29(a)	0.57	0.41	3.74(a,b)
2003				
Revenues	$ 172,335	$ 152,862	$ 146,437	$ 143,113
Operating income	58,911	49,205	43,223	35,407(a)
Provision for income taxes	15,891	11,501	10,160	4,302(a)
Income (loss) before cumulative effect of change in accounting principle	33,562	(8,689)(c)	11,757	(284,656)(a,d)
Net income (loss)	40,681	(8,689)(c)	11,757	(284,656)(a,d)
Income (loss) before cumulative effect of change in accounting principle per share:				
Basic	0.53	(0.14)(c)	0.18	(4.43)(a,d)
Diluted	0.53	(0.13)(c)	0.18	(4.39)(a,d)
Net income (loss) per share:				
Basic	0.64	(0.14)(c)	0.18	(4.43)(a,d)
Diluted	0.64	(0.13)(c)	0.18	(4.39)(a,d)

(a) The quarters ended March 31, 2004, December 31, 2004 and December 31, 2003, include impairment of proved oil and gas properties of $3.9 million ($2.4 million net of tax or $0.04 per share), $2.1 million ($1.3 million net of tax or $0.02 per share), and $6.1 million ($3.7 million net of tax or $0.06 per share), respectively.

(b) The quarter ended December 31, 2004, includes a gain on sale of discontinued Canadian operations of $198.5 million or $3.02 per basic share and $2.98 per diluted share.

(c) The quarter ended June 30, 2003, includes impairments of Canadian proved oil and gas properties of $12.6 million ($7.3 million net of tax or $0.11 per share) and Canadian exploration cost of $23.7 million ($13.9 million net of tax or $0.22 per share) to fully impair the Company's undeveloped leaseholds in the Northwest Territories. These amounts are included in losses from discontinued operations.

(d) The quarter ended December 31, 2003, includes a Canadian goodwill impairment of $25.7 million ($0.40 per share) and impairments of Canadian proved oil and gas properties of $350.1 million ($265.7 million net of tax or 4.13 per basic share and $4.10 per diluted share). These amounts are included in losses from discontinued operations.

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, 2004, 2003 and 2002. The results of operations related to the Company's discontinued operations in Trinidad, Ecuador and Canada have been excluded for all periods presented (see Note 7).

	2004					
(In thousands)	U.S.	Argentina	Bolivia	Yemen	Other	Total
Revenues	$ 350,565	$ 319,985	$ 15,908	$ 20,246	$ -	$ 706,704
Production and operating costs	111,655	104,914	4,710	4,184	-	225,463
Exploration costs	19,374	4,124	-	2,660	5,835	31,993
Impairment of proved properties	6,049	-	-	-	-	6,049
Depreciation, depletion and amortization	51,634	43,671	3,277	1,861	-	100,443
Accretion	3,819	2,715	82	10	-	6,626
Results of operations before income taxes	158,034	164,561	7,839	11,531	(5,835)	336,130
Income tax expense	61,475	64,343	1,960	4,255	-	132,033
Results of operations (excluding corporate overhead and interest costs)	$ 96,559	$ 100,218	$ 5,879	$ 7,276	$ (5,835)	$ 204,097

	2003					
(In thousands)	U.S.	Argentina	Bolivia	Yemen	Other	Total
Revenues	$ 253,508	$ 276,131	$ 14,475	$ -	$ -	$ 544,114
Production and operating costs	96,677	84,961	4,608	-	-	186,246
Exploration costs	13,805	-	1,286	4,739	1,777	21,607
Impairment of proved properties	6,050	-	-	-	-	6,050
Depreciation, depletion and amortization	38,215	43,518	2,815	-	-	84,548
Accretion	3,463	2,421	96	-	-	5,980
Results of operations before income taxes	95,298	145,231	5,670	(4,739)	(1,777)	239,683
Income tax expense (benefit)	37,071	56,074	1,418	(1,659)	(622)	92,282
Results of operations (excluding corporate overhead and interest costs)	$ 58,227	$ 89,157	$ 4,252	$ (3,080)	$ (1,155)	$ 147,401

(In thousands)	2002 U.S.	Argentina	Bolivia	Yemen	Other	Total
Revenues	$ 219,455	$ 232,787	$ 12,345	$ -	$ -	$ 464,587
Production and operating costs	92,795	67,681	4,494	-	-	164,970
Exploration costs	10,679	-	-	12,215	48	22,942
Impairment of proved properties	16,972	-	-	-	-	16,972
Depreciation, depletion and amortization	51,025	46,067	3,564	-	-	100,656
Results of operations before income taxes	47,984	119,039	4,287	(12,215)	(48)	159,047
Income tax expense (benefit)	18,666	34,908	1,072	(4,275)	(17)	50,354
Results of operations (excluding corporate overhead and interest costs)	$ 29,318	$ 84,131	$ 3,215	$ (7,940)	$ (31)	$ 108,693

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

The capitalized costs and costs incurred related to the Company's discontinued operations in Trinidad, Ecuador and Canada have been excluded for all periods presented (see Note 7). The Company's net investment in oil and gas properties at December 31, 2004 and 2003, was as follows:

(In thousands)	2004 U.S.	Argentina	Bolivia	Yemen	Other	Total
Unproved properties not being amortized	$ 10,802	$ -	$ -	$ 14,569	$ -	$ 25,371
Proved properties being amortized	1,107,033	872,483	118,404	39,885	-	2,137,805
Total capitalized costs	1,117,835	872,483	118,404	54,454	-	2,163,176
Less accumulated depreciation, depletion and amortization	574,492	301,933	29,715	2,039	-	908,179
Net capitalized costs	$ 543,343	$ 570,550	$ 88,689	$ 52,415	$ -	$ 1,254,997

(In thousands)	2003 U.S.	Argentina	Bolivia	Yemen	Other	Total
Unproved properties not being amortized	$ 16,832	$ -	$ -	$ 11,756	$ 847	$ 29,435
Proved properties being amortized	928,612	747,805	117,864	11,872	-	1,806,153
Total capitalized costs	945,444	747,805	117,864	23,628	847	1,835,588
Less accumulated depreciation, depletion and amortization	514,913	256,485	26,426	-	-	797,824
Net capitalized costs	$ 430,531	$ 491,320	$ 91,438	$ 23,628	$ 847	$ 1,037,764

Net capitalized costs for the Company's discontinued operations in Canada as of December 31, 2003, were approximately $176.4 million.

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 2004, 2003 and 2002:

	2004					
(In thousands)	U.S.	Argentina	Bolivia	Yemen	Other	Total
Acquisitions:						
Unproved properties	$ 9,623	$ -	$ -	$ -	$ -	$ 9,623
Proved properties	75,599	34,948	-	-	-	110,547
Exploratory	34,616	4,124	-	3,554	5,292	47,586
Development	60,606	89,086	-	30,142	-	179,834
	180,444	128,158	-	33,696	5,292	347,590
Asset retirement obligations:						
Assets purchased	2,939	1,156	-	-	-	4,095
New wells	1,267	562	-	537	-	2,366
Changes in estimates	3,757	91	540	330	-	4,718
	7,963	1,809	540	867	-	11,179
Total costs incurred	$ 188,407	$ 129,967	$ 540	$ 34,563	$ 5,292	$ 358,769

	2003					
(In thousands)	U.S.	Argentina	Bolivia	Yemen	Other	Total
Acquisitions:						
Unproved properties	$ 3,822	$ -	$ -	$ -	$ 78	$ 3,900
Proved properties	463	-	-	-	-	463
Exploratory	21,866	-	1,286	12,370	2,458	37,980
Development	48,309	58,332	367	-	-	107,008
	74,460	58,332	1,653	12,370	2,536	149,351
Asset retirement obligations:						
New wells	765	362	-	99	-	1,226
Changes in estimates	4,170	37	(250)	-	-	3,957
	4,935	399	(250)	99	-	5,183
Total costs incurred	$ 79,395	$ 58,731	$ 1,403	$ 12,469	$ 2,536	$ 154,534

	2002											
(In thousands)		U.S.		Argentina		Bolivia		Yemen		Other		Total
Acquisitions:												
Unproved properties	$	1,981	$	-	$	-	$	338	$	52	$	2,371
Proved properties		-		-		-		-		-		-
Exploratory		15,748		-		-		7,348		47		23,143
Development		11,758		19,008		2,625		-		-		33,391
Total costs incurred	$	29,487	$	19,008	$	2,625	$	7,686	$	99	$	58,905

Costs incurred for the Company's discontinued operations in Canada for 2004, 2003 and 2002 were approximately $17.7 million, $34.1 million and $58.6 million, respectively.

Costs incurred for the Company's discontinued operations in Ecuador for 2003 and 2002, were approximately $1.1 million and $12.2 million, respectively.

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, Yemen, 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 DeGolyer and MacNaughton Canada Limited (formerly Outtrim Szabo Associates Ltd.), with the following exceptions. The Company estimated approximately six percent of the total proved reserves for the United States and approximately three percent of the total proved reserves for Argentina as of December 31, 2004 (only approximately four percent of total Company proved reserves).

	Oil (MBbls)							
	U.S.	Canada	Argentina	Bolivia	Yemen	Ecuador	Trinidad	Total
Proved reserves at December 31, 2001	76,948	21,808	175,827	6,135	-	50,357	1,186	332,261
Revisions of previous estimates	15,498	(1,936)	12,413	47	-	(4,121)	-	21,901
Extensions, discoveries and other additions	4,896	447	12,096	-	-	382	-	17,821
Production	(6,796)	(1,829)	(10,942)	(118)	-	(1,174)	-	(20,859)
Purchase of reserves-in-place	-	-	-	-	-	-	-	-
Sales of reserves-in-place	(1,241)	-	-	-	-	-	(1,186)	(2,427)
Proved reserves at December 31, 2002	89,305	18,490	189,394	6,064	-	45,444	-	348,697
Revisions of previous estimates	(15)	(13,296)	4,567	62	-	-	-	(8,682)
Extensions, discoveries and other additions	4,709	302	8,945	-	3,137	-	-	17,093
Production	(6,199)	(1,248)	(10,388)	(83)	-	(114)	-	(18,032)
Purchase of reserves-in-place	90	-	-	-	-	-	-	90
Sales of reserves-in-place	(286)	(752)	-	-	-	(45,330)	-	(46,368)
Proved reserves at December 31, 2003	87,604	3,496	192,518	6,043	3,137	-	-	292,798
Revisions of previous estimates	3,229	(64)	(7,092)	(363)	630	-	-	(3,660)
Extensions, discoveries and other additions	504	222	12,035	-	2,544	-	-	15,305
Production	(6,153)	(830)	(9,900)	(89)	(514)	-	-	(17,486)
Purchase of reserves-in-place	5,690	-	7,411	-	-	-	-	13,101
Sales of reserves-in-place	-	(2,824)	-	-	-	-	-	(2,824)
Proved reserves at December 31, 2004	90,874	-	194,972	5,591	5,797	-	-	297,234
Proved developed oil reserves at:								
December 31, 2002	75,547	10,620	106,135	4,721	-	8,302	-	205,325
December 31, 2003	75,545	3,462	103,973	5,632	-	-	-	188,612
December 31, 2004	82,141	-	108,692	3,723	4,786	-	-	199,342

	Gas (MMcf)						Total
	U.S.	Canada	Argentina	Bolivia	Trinidad	Total	(MBOE)
Proved reserves at December 31, 2001	325,149	236,112	131,394	459,660	64,409	1,216,724	535,048
Revisions of previous estimates	9,367	(37,750)	1	814	-	(27,568)	17,307
Extensions, discoveries and other additions	9,243	14,614	5,399	-	-	29,256	22,697
Production	(24,841)	(29,951)	(8,630)	(6,424)	-	(69,846)	(32,500)
Purchase of reserves-in-place	-	-	-	-	-	-	-
Sales of reserves-in-place	(611)	-	-	-	(64,409)	(65,020)	(13,264)
Proved reserves at December 31, 2002	318,307	183,025	128,164	454,050	-	1,083,546	529,288
Revisions of previous estimates	3,533	(82,506)	(477)	685	-	(78,765)	(21,810)
Extensions, discoveries and other additions	24,545	2,410	5,438	-	-	32,393	22,492
Production	(23,097)	(19,153)	(9,838)	(6,252)	-	(58,340)	(27,755)
Purchase of reserves-in-place	258	-	-	-	-	258	133
Sales of reserves-in-place	(36,015)	(17,039)	-	-	-	(53,054)	(55,210)
Proved reserves at December 31, 2003	287,531	66,737	123,287	448,483	-	926,038	447,138
Revisions of previous estimates	(6,502)	3,912	15,628	(12,525)	-	513	(3,575)
Extensions, discoveries and other additions	13,377	5,786	585	-	-	19,748	18,596
Production	(30,459)	(14,077)	(8,659)	(8,097)	-	(61,292)	(27,701)
Purchase of reserves-in-place	17,381	-	-	-	-	17,381	15,998
Sales of reserves-in-place	-	(62,358)	-	-	-	(62,358)	(13,217)
Proved reserves at December 31, 2004	281,328	-	130,841	427,861	-	840,030	437,239
Proved developed gas reserves at:							
December 31, 2002	245,854	161,200	43,736	353,259	-	804,049	339,333
December 31, 2003	228,435	66,433	35,645	384,393	-	714,906	307,763
December 31, 2004	239,629	-	42,371	281,167	-	563,167	293,203

Proved reserves at December 31, 2004, 2003, 2002 and 2001, include 49.2 MMBbls of oil and 9.9 Bcf of gas (50.9 MMBOE), 46.0 MMBbls of oil and 13.3 Bcf of gas (48.2 MMBOE), and 41.6 MMBbls of oil and 10.5 Bcf of gas (43.3 MMBOE) and 26.2 MBbls of oil and 4.6 Bcf of gas (27.0 MMBOE), respectively, related to the 10 year extension periods contained in the Company's Argentina concession agreements. Upon approval by the government, the extension periods begin in 2015 through 2017, depending on the effective date each concession agreement was granted. We believe, based on historical precedent, that such extensions will be obtained as a matter of course.

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 production costs include the effect of the Argentine oil export tax discussed in Note 1 through February 2007, the term limited by law. Future income taxes were computed by applying the statutory tax rate to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved oil and gas properties. Tax credits and permanent differences were also considered in the future income tax calculation. Future net cash inflows after income taxes were discounted using a 10 percent annual discount rate to arrive at the Standardized Measure.

Set forth below is the Standardized Measure relating to proved oil and gas reserves at December 31, 2004, 2003 and 2002 (in thousands):

	2004				
	U.S.	Argentina	Bolivia	Yemen	Total
Future cash inflows	$ 4,910,511	$ 5,887,603	$ 457,500	$ 211,930	$ 11,467,544
Future production costs	1,828,220	1,612,833	64,960	36,659	3,542,672
Future development and abandonment costs	325,571	525,017	67,753	28,508	946,849
Future net cash inflows before income tax expense	2,756,720	3,749,753	324,787	146,763	6,978,023
Future income tax expense	964,682	1,266,370	69,902	27,636	2,328,590
Future net cash flows	1,792,038	2,483,383	254,885	119,127	4,649,433
10 percent annual discount for estimated timing of cash flows	787,958	1,208,262	158,984	18,659	2,173,863
Standardized Measure of discounted future net cash flows	$ 1,004,080	$ 1,275,121	$ 95,901	$ 100,468	$ 2,475,570

	2003					
	U.S.	Canada	Argentina	Bolivia	Yemen	Total
Future cash inflows	$ 4,239,048	$ 456,145	$ 5,353,246	$ 498,065	$ 101,069	$ 10,647,573
Future production costs	1,561,174	167,115	1,427,478	57,997	28,643	3,242,407
Future development and abandonment costs	280,585	2,425	434,127	62,163	38,142	817,442
Future net cash inflows before income tax expense	2,397,289	286,605	3,491,641	377,905	34,284	6,587,724
Future income tax expense	835,749	-	1,183,049	80,578	10,728	2,110,104
Future net cash flows	1,561,540	286,605	2,308,592	297,327	23,556	4,477,620
10 percent annual discount for estimated timing of cash flows	697,421	76,695	1,110,466	201,520	8,990	2,095,092
Standardized Measure of discounted future net cash flows	$ 864,119	$ 209,910	$ 1,198,126	$ 95,807	$ 14,566	$ 2,382,528

	2002					
	U.S.	Canada	Argentina	Bolivia	Ecuador	Total
Future cash inflows	$ 3,941,678	$ 1,269,173	$ 5,018,746	$ 507,753	$ 967,509	$ 11,704,859
Future production costs	1,448,897	311,575	1,135,635	59,005	180,476	3,135,588
Future development and abandonment costs	298,454	57,749	393,922	73,425	159,814	983,364
Future net cash inflows before income tax expense	2,194,327	899,849	3,489,189	375,323	627,219	7,585,907
Future income tax expense	747,251	251,847	1,204,976	76,671	131,891	2,412,636
Future net cash flows	1,447,076	648,002	2,284,213	298,652	495,328	5,173,271
10 percent annual discount for estimated timing of cash flows	663,265	233,150	1,139,895	208,239	182,465	2,427,014
Standardized Measure of discounted future net cash flows	$ 783,811	$ 414,852	$ 1,144,318	$ 90,413	$ 312,863	$ 2,746,257

The Standardized Measure at December 31, 2004, 2003 and 2002 includes \$117.1 million, \$92.6 million and \$85.6 million, respectively, related to the 10 year extension periods of the Company's Argentina concession agreements. Upon approval by the government, the extension periods begin in 2015 through 2017, depending on the effective date each concession agreement was granted. We believe, based on historical precedent, that such extensions will be obtained as a matter of course.

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 2004, 2003 and 2002 (in thousands):

	2004	2003	2002
Standardized Measure - beginning of year	$ 2,382,528	$ 2,746,257	$ 1,438,141
Increases (decreases) -			
Sales, net of production costs	(532,801)	(436,079)	(406,443)
Net change in sales prices, net of production costs	362,150	127,952	2,218,644
Discoveries and extensions, net of related future development and production costs	242,949	233,579	196,774
Changes in estimated future development costs	(134,030)	(43,111)	13,094
Development costs incurred	189,550	118,825	75,186
Revisions of previous quantity estimates	1,917	(282,667)	159,423
Accretion of discount	350,768	361,112	190,427
Net change in income taxes	(138,480)	137,920	(787,133)
Purchase of reserves-in-place	208,468	970	-
Sales of reserves-in-place	(245,873)	(508,019)	(11,008)
Timing of production of reserves and other	(211,576)	(74,211)	(340,848)
Standardized Measure - end of year	$ 2,475,570	$ 2,382,528	$ 2,746,257

EXHIBIT 31.1

CERTIFICATION PURSUANT TO
RULE 13a-14(a) AND
SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, C.C. Stephenson, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Vintage Petroleum, Inc.;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: March 11, 2005

\s\ C.C. Stephenson, Jr.
C.C. Stephenson, Jr.
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, William C. Barnes, certify that:

1. I have reviewed this annual report on Form 10-K of Vintage Petroleum, Inc.;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: March 11, 2005

\s\ William C. Barnes
William C. Barnes
Chief Financial Officer

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Annual Stockholders' Meeting

Our annual stockholders' meeting will be held Tuesday, May 10, 2005, at 10:00 a.m. (CDT).

Independent Auditors

Ernst & Young LLP

Independent Reserve Engineers

Netherland, Sewell & Associates, Inc.
DeGolyer and MacNaughton

Stock Market Information

The company's common stock is traded on the New York Stock Exchange under the symbol VPI. The table below reflects the high and low sales prices per share during each quarter of 2004 and 2003.

	2004		2003	
	High	Low	High	Low
March 31	$15.60	$11.52	$11.46	$ 9.00
June 30	$17.58	$13.61	$12.34	$ 9.10
September 30	$20.53	$15.11	$12.10	$10.51
December 31	$24.50	$19.10	$12.93	$10.14

The company's quarterly cash dividend of 4-1/2 cents per share on February 23, 2004, was increased to 5 cents per share on May 11, 2004.

Corporate Office

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Investor Contact

Robert E. Phaneuf
Vice President – Corporate Development
Telephone: 918-592-0101

Transfer Agent and Registrar

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www.melloninvestor.com

Mellon Investor Services, our transfer agent, maintains the records for our registered shareholders and can help you with a variety of shareholder related services at no charge. Shareholder questions regarding stock certificates, online access to account information, e-mail delivery of shareholder materials, change of name or address, lost stock certificates and other administrative services pertaining to common shares of Vintage Petroleum, Inc. should be directed to Mellon Investor Services LLC at the addresses or phone number above.

Annual CEO Certification

The Annual CEO Certification regarding the New York Stock Exchange's corporate governance listing standards required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual was provided to the New York Stock Exchange on June 8, 2004.

Forward-looking Statements:

This Annual Report includes certain statements that may be deemed to be "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. All statements in this Annual Report, other than statements of historical facts, that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future, including future capital expenditures (including the amount and nature thereof), the drilling of wells, reserve estimates, future production of oil and gas, future discretionary cash flows, future reserve activity and other such matters are forward-looking statements. Although the Company believes the expectations expressed in such forward-looking statements are based on reasonable assumptions within the bounds of its knowledge of its business, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements.

Factors that could cause actual results to differ materially from those in forward-looking statements include: oil and gas prices; exploitation and exploration successes; actions taken or to be taken by foreign governments as a result of their political and economic circumstances and changes in the estimated or expected impact on the Company; continued availability of capital and financing; general economic, market or business conditions; acquisition opportunities (or lack thereof); changes in laws or regulations; risk factors listed from time to time in the Company's filings with the Securities and Exchange Commission; and other factors. The Company assumes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

Design by Falk Harrison Creative, St. Louis, Missouri www.falkharrison.com

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