POGO PRODUCING CO
Form 10-K
February 27, 2003

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2002

o **TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the transition period from to

Commission File No. 1-7792

Pogo Producing Company

(Exact name of registrant as specified in its charter)

Delaware	**74-1659398**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
5 Greenway Plaza, P.O. Box 2504 Houston, Texas	**77252-2504**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code: **(713) 297-5000**

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

Title of each class:	Name of each exchange on which registered:
Common Stock, $1 par value	**New York Stock Exchange**
	Pacific Exchange
Preferred Stock Purchase Rights	**New York Stock Exchange**

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

5½% Convertible Subordinated Notes due June 15, 2006

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 ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

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

The aggregate market value of the Common Stock held by non-affiliates of the registrant (treating all executive officers and directors of the registrant, for this purpose, as if they may be affiliates of the registrant) was approximately $1,981,295,154 as of June 30, 2002 (based on $32.62 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange Composite Tape on such date).

61,201,834 shares of the registrant s Common Stock were outstanding as of February 26, 2003.

DOCUMENT INCORPORATED BY REFERENCE

Portions of the Company s definitive Proxy Statement respecting the annual meeting of shareholders to be held on April 22, 2003 (to be filed not later than 120 days after December 31, 2002) are incorporated by reference in Part III of this Form 10-K.

FORWARD LOOKING STATEMENTS

The statements included or incorporated by reference in this Annual Report on Form 10-K for the year ended December 31, 2002 (this Annual Report) include 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 included or incorporated by reference herein, other than statements of historical fact, are forward-looking statements. In some cases, you can identify our forward-looking statements by the words anticipate, estimate, expect, objective, projection, forecast, goal, and similar expressions. Such forward-looking statements include, without limitation, the statem herein and therein regarding the timing of future events regarding the operations of Pogo Producing Company (the Company) and its subsidiaries, and the statements under the caption Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources regarding the Company s anticipated future financial position and cash requirements. Although the Company believes that the expectations reflected in these forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from the Company s expectations (Cautionary Statements) are disclosed in this Annual Report and in other filings by the Company with the Securities and Exchange Commission (the Commission). All subsequent written and oral forward-looking statements attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements. The Company s actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and other factors set forth in or incorporated by reference in this Annual Report. These factors include:

the cyclical nature of the oil and natural gas industries

our ability to successfully and profitably find, produce and market oil and gas

uncertainties associated with the United States and worldwide economies

current and potential governmental regulatory actions in countries where the Company operates

substantial competition from larger companies

the Company s ability to implement cost reductions

operating interruptions (including leaks, explosions, fires, mechanical failure, unscheduled downtime, transportation interruptions, and spills and releases and other environmental risks) fluctuations in foreign currency exchange rates in areas of the world where the Company conducts operations, particularly Southeast Asia

covenant restrictions in the Company s debt agreements

Many of those factors are beyond the Company s ability to control or predict. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements or present or prior earnings levels.

All subsequent written and oral forward-looking statements attributable to the Company and persons acting on the Company s behalf are qualified in their entirety by the Cautionary Statements contained in this section and elsewhere in this Annual Report.

CERTAIN DEFINITIONS

As used in this Annual Report, Mcf means thousand cubic feet, MMcf means million cubic feet, Bcf means billion cubic feet, Bbl means barrel MBbls means thousand barrels and MMBbls means million barrels. BOE means barrel of oil equivalent, Mcfe means thousand cubic feet of natural gas equivalent, MMcfe means million cubic feet of natural gas equivalent and Bcfe means billion cubic feet of natural gas equivalent. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (NGL). References to $ and dollars refer to United States dollars. All estimates of reserves contained in this Annual Report, unless otherwise noted, are reported on a net basis. Information regarding production, acreage and numbers of wells are set forth on a gross basis, unless otherwise noted.

PART I

ITEM 1. ***Business.***

The Company was incorporated in 1970 and is engaged in oil and gas exploration, development, acquisition and production activities on its properties located offshore in the Gulf of Mexico, onshore in selected areas including Texas, New Mexico, Wyoming and Louisiana, and internationally, primarily in the Gulf of Thailand and in Hungary. As of December 31, 2002, the Company had interests in 69 lease blocks offshore Louisiana and Texas, approximately 415,000 gross acres onshore in the United States, approximately 714,000 gross acres offshore in the Kingdom of Thailand, approximately 194,000 gross acres in the Danish and British sectors of the North Sea and approximately 782,000 gross acres in Hungary.

On March 14, 2001, the Company acquired North Central Oil Corporation (North Central) through a direct merger with its parent company, NORIC Corporation (NORIC). The Company accounted for the merger using the purchase method of accounting. Therefore, the information contained in this Annual Report does not reflect the operations of North Central prior to that date. In connection with the merger, the Company paid $344,711,000 in cash to the former shareholders of NORIC, issued them 12,615,816 shares of Common Stock, and assumed approximately $78,600,000 of North Central s debt.

The Company organizes its exploration and production activities principally into five operating regions and a New Ventures Group. The operating regions are its Gulf of Mexico region, which is responsible for the Company s operations offshore Texas and Louisiana in the Gulf of Mexico; its Western U.S. region, which is active in the Permian Basin area in New Mexico and West Texas and in the Madden Field in Wyoming; its Gulf Coast region, which includes the Company s onshore operations principally in South Texas and Louisiana; the Asia and Pacific region, which has responsibility for the Company s operations on its Block B8/32 Concession in the Kingdom of Thailand (the Thailand Concession), and its Europe region, which is currently active principally in Hungary and the North Sea. The Company s New Ventures Group is primarily responsible for identifying new projects and opportunities for the Company outside the United States.

Domestic Offshore Operations

Gulf of Mexico Region. Historically, the Company s interests have been concentrated in the Gulf of Mexico, where approximately 26% of the Company s proved reserves were located as of December 31, 2002. During 2002, approximately 27% of the Company s natural gas production and 50% of its oil and condensate production came from the Company s domestic offshore properties, contributing approximately 43% of the Company s consolidated oil and gas revenues. The Company s exploration and development efforts are primarily focused in the shallower waters of the continental shelf.

Exploration and Development

The scope of exploration and development programs relating to the Company s offshore interests is affected by prices for oil and gas, and by federal, state and local legislation, regulations and ordinances applicable to the petroleum industry. The Company s domestic offshore capital and exploration expenditures for 2002 were approximately $130,265,000, or 24% lower than the Company s domestic offshore capital and exploration expenditures of approximately $170,800,000 (excluding approximately $87,700,000 of net property acquisitions principally related to the North Central acquisition) for 2001, and 105% higher than the Company s domestic offshore capital and exploration expenditures of approximately $63,600,000 for 2000. The decrease in the Company s domestic offshore capital and exploration expenditures for 2002, compared with 2001, resulted primarily from decreased expenditures for facilities construction. During 2002, the Company invested approximately $51,800,000 on facilities construction for its Gulf of Mexico operations, principally the fabrication and installation of platforms in the Company s Main Pass Blocks 61/62 Field. The Company has currently budgeted approximately $60,000,000 for capital and exploration expenditures during 2003 in the Gulf of Mexico, of which $11,600,000 is budgeted for facilities construction.

The Company maintains a significant presence in the Gulf of Mexico where it participated in drilling 20 wells during 2002, 90% of which were considered successful. At December 31, 2002, the Company held varying interests in 248 producing oil and gas wells in the Gulf of Mexico.

Leases acquired by the Company and other participants in its bidding groups are customarily committed, on a block-by-block basis, to separate operating agreements under which the appointed operator supervises exploration and development operations for the account and at the expense of the group. These agreements usually contain terms and conditions that have become relatively standardized in the industry. Major decisions regarding development and operations typically require the consent of at least a majority (in working interest) of the participants. Because the Company generally has a meaningful working interest position, the Company believes it can significantly influence (but not always control) decisions regarding development and operations on most of the leases in which it has a working interest even though it may not be the operator of a particular lease. The Company is the operator on all or a portion of 33 of the 69 offshore leases in which it had an interest on December 31, 2002.

Platforms and related facilities are installed on an offshore lease block when, in the judgment of the lease interest owners, the necessary capital expenditures are justified. A decision to install a platform generally is made after the drilling of one or more exploratory wells with contracted drilling equipment. Platform costs vary depending on, among other factors, the number of well slots, water depth, currents, and sea floor conditions. During 2002, the Company completed the installation of an additional production platform and a pressure maintenance platform, together with related facilities, in its new, wholly owned Main Pass Blocks 61/62 Field. The average cost of constructing and installing these two platforms was approximately $27,000,000 per platform.

Lease Acquisitions

The Company has participated, either on its own or with other companies, in bidding on and acquiring interests in federal and state leases offshore in the Gulf of Mexico since 1970. As a result of such purchases and subsequent activities, as of December 31, 2002, the Company owned interests in 56 federal leases and 13 state leases offshore Louisiana and Texas. Federal leases generally have primary terms of five, eight or ten years, depending on water depth, and state leases generally have terms of three or five years, depending on location, in each case subject to extension by development and production operations.

As part of its strategy, the Company intends to continue an active lease evaluation program in the Gulf of Mexico in order to identify exploration and exploitation opportunities. The Company acquires leases through participation in federal and state lease sales, farmouts and by acquisition. For example, the Company acquired six offshore leases at the lease sale conducted by the Minerals Management Service of the Department of the Interior (the MMS) on March 20, 2002. The Company also acquired three state leases through sales conducted by the State of Louisiana in 2002. The Company also maintains an active asset rationalization process through which it seeks to sell or farmout blocks that the Company believes have little or no remaining upside potential, or face significant future expenditures that would likely result in a rate of return which does not meet the Company s internal criteria. As part of this process, the Company sold one lease in 2002. The extent to which the Company participates in future bidding on federal or state offshore lease sales or otherwise acquires additional lease blocks will depend on the availability of funds and its estimates of hydrocarbon deposits, operating expenses and future revenues that may reasonably be expected from available lease blocks. Such estimates typically take into account, among other things, estimates of future hydrocarbon prices, federal regulations and taxation policies applicable to the petroleum industry. It is also the Company s objective to acquire certain producing leasehold properties in areas where additional low-risk exploration and development drilling or improved production methods can provide attractive rates of return.

Domestic Onshore Operations

The Company s Gulf Coast region is headquartered in Houston, Texas, with field offices in Laredo and Manvel, Texas. The Company s Western U.S. region has an office in Midland, Texas and two field offices in Southeastern New Mexico. The Company conducts its onshore operations in the United States directly and through its wholly owned subsidiaries, North Central and Arch Petroleum Inc. (Arch). Domestic onshore reserves as of December 31, 2002, accounted for approximately 50% of the Company s total proved reserves, with the Gulf Coast region and the Western U.S. region contributing approximately 20% and 30%, respectively, of the Company s total proved

4

reserves. During 2002, approximately 45% of the Company s natural gas production and 18% of its oil and condensate production was from its domestic onshore properties, contributing approximately 25% of the Company s consolidated oil and gas revenues.

Exploration and Development

Western U.S. Region. The Company s Western U.S. region has actively explored in the west Texas and southeast New Mexico areas for over 23 years. Since the Company began exploring in the Brushy Canyon (Delaware) formation in 1989, it has participated in drilling 523 wells in west Texas and southeast New Mexico through December 31, 2002, including 45 wells in 2002 (92% of which were successfully completed), and participated in the discovery or development of over 27 oil and gas fields during that time. The Company believes that during the past ten years it has been one of the most active companies drilling for oil and natural gas in southeastern New Mexico (Lea and Eddy Counties), where the Company has interests in approximately 128,000 gross acres. The Company currently plans to drill approximately 82 wells in the Permian Basin during 2003 in 22 known fields and exploratory prospects. Drilling objectives of these wells range in depth from 3,700 feet to 15,800 feet below the surface, and target numerous formations including, among others, the shallow Queen, Delaware (Brushy Canyon), Bone Springs, Spraberry and Strawn formations, to the deeper Morrow, Devonian and Ellenburger pay zones.

The Company s Western U.S. region also actively participates in the exploration and development of the Madden Deep Unit in central Wyoming, where the Company owns varying working interests that average approximately 12.5% across the unit area. The Madden Deep Unit consists of two principal producing formations, the comparatively shallow Lower Fort Union formation (where productive zones are historically found from approximately 5,500 feet to 9,500 feet below the surface) and the Madison formation (which currently produces from zones located approximately 23,500 feet to 25,000 feet below the surface). The gas produced from the Lower Fort Union formation is comparatively dry sweet gas. Gas produced from the Madison formation, however, contains significant quantities (approximately one-third by volume) of carbon dioxide and hydrogen sulfide gases. Gas from the Madison zones must be processed through the Lost Cabin Gas Plant to remove the carbon dioxide and hydrogen sulfide gases prior to sale. An expansion of the Lost Cabin Gas Plant was completed in 2002, which increased the plant s processing capacity from 132 MMcf per day to approximately 313 MMcf per day. The Company owns a 12.4% working interest in this plant. The wells to the Madison formation are deep and technologically challenging to drill, taking up to 13 months from commencement to completion. Two Madison tests (the Bighorn 7-34 and Bighorn 8-35) were successfully completed as producing gas wells during 2002. Additionally, the Big Horn 9-4 is being drilled and is currently projected to reach total depth and completed during 2003. An active Lower Fort Union drilling program is also anticipated for 2003.

Gulf Coast Region. The Company s Gulf Coast region is actively exploring in Louisiana, east Texas and south Texas. During 2002, the Gulf Coast region participated in drilling 44 wells, 89% of which were successfully completed. In southeast Louisiana, the Company drilled and completed two wells during 2002 on prospects that were identified through the Company s Thibodaux 3-D seismic survey, which covers approximately 39,000 acres. The Company currently plans to drill two wells in this area during 2003.

In south Texas, the Company s Gulf Coast region is active in its Los Mogotes, Hundido and Hereford Ranch Fields, that produce from the Asche, Charco and Lobo formations, and which are found at depths ranging from 7,000 to 14,000 feet below the surface. In its Los Mogotes Field, where its working interest averages approximately 72%, the Company drilled 26 wells in 2002 utilizing up to three drilling rigs at various times during that period. The Company currently has two rigs working in the field and has budgeted to drill 21 wells there during 2003. In addition, the Company enjoys significant production from its Hundido Field, where it has an average approximate 98% working interest and from the

Company s Hereford Ranch Field, where it has a 100% working interest.

The Company generally conducts its onshore activities through joint ventures and other interest-sharing arrangements with major and independent oil companies. The Company and its subsidiaries operate many of their onshore properties using both independent contractors and field personnel that are employed by the Company or its subsidiaries.

The Company s onshore capital and exploration expenditures for 2002 were approximately $75,000,000, or 47% lower than the Company s onshore capital and exploration expenditures of approximately $141,000,000 (excluding approximately $1,027,200,000 of net property acquisitions primarily related to the acquisition of North Central) for 2001, and 36% higher than the Company s onshore capital and exploration expenditures of approximately $55,100,000 (excluding approximately $8,400,000 of net property acquisitions) for 2000. The decrease in the Company s onshore capital and exploration expenditures for 2002, compared to 2001, resulted primarily from expenditures related to increased exploratory and development drilling in its other core areas. The

Company has currently budgeted approximately $117,000,000 for capital and exploration expenditures during 2003 in its domestic onshore areas.

Lease Acquisitions

As it has in recent years, in 2002 the Company also successfully participated in various onshore federal and state lease sales and acquired interests in other prospective acreage. As of December 31, 2002, the Company held interests in approximately 415,000 (228,000 net) acres onshore in the United States.

International Operations

The Company has conducted international exploration activities since the late 1970 s in numerous oil and gas areas throughout the world. The Company currently holds licenses in the Kingdom of Thailand, Hungary and the Danish and British sectors of the North Sea. In addition, the Company s international explorationists continue to evaluate other international opportunities that are consistent with its international exploration strategy and expertise.

Substantial portions of the Company s international operations are grouped under its wholly owned Dutch subsidiary, Pogo Overseas Production B.V. Two subsidiaries of Pogo Overseas Production B.V., Thaipo Limited (Thaipo) and Pogo Hungary Ltd., maintain offices in Bangkok, Thailand and in Budapest, Hungary, respectively.

Exploration and Development

The Company s international capital and exploration expenditures were approximately $103,200,000 for 2002, or 47% higher than the Company s international capital and exploration expenditures of $70,100,000 for 2001, and 93% higher than the Company s international capital and exploration expenditures of approximately $53,400,000 for 2000. The increase in the Company s capital and exploration expenditures for 2002, compared to 2001 and 2000, resulted primarily from expenditures for facilities costs, including construction and installation of five platforms for installation in the Benchamas Field and increased drilling expenses resulting from having two rigs drilling in Thailand for a substantial portion of the year. Substantially all of the Company s international capital and exploration expenditures for 2002 were related to the Company s license in the Kingdom of Thailand. During 2001 and 2000, a significant portion of the Company s exploration expenditures occurred outside of Thailand; including approximately $9,020,000 in exploration expenditures in 2001 and $3,396,000 in 2000, all of which related to 3-D seismic data acquisition in Hungary.

The Company has currently budgeted approximately $143,000,000 for capital and exploration expenditures during 2003 in areas outside the United States, including $120,000,000 in Thailand and $23,000,000 in Europe, of which approximately $3.4 million is designated for the Danish sector of the North Sea and the remainder is designated for the Company s operations in Hungary. Approximately $67,700,000 of these funds are budgeted for facilities upgrades and additions in the Kingdom of Thailand, including the construction of eight platforms for the Thailand Concession, three of which are planned to be installed in late 2003 and five of which are projected to be installed in 2004.

Asia and Pacific Region.

The Company currently owns, directly or indirectly, a 46.34% working interest in the entire Thailand Concession. The remainder of the working interest is owned, directly or indirectly, by Chevron Offshore (Thailand) Limited (Chevron) (46.34%), a subsidiary of Chevron Corporation, and Palang Sophon Limited (Palang) (7.32%). Through its majority ownership of Palang, Chevron owns or controls, directly or indirectly, 51.66% of the working interests in the Thailand Concession and is currently the operator of the Thailand Concession. Through voting procedures in the joint operating agreement governing the Thailand Concession, and the close working relationship between Chevron s and Thaipo s exploration staffs, Thaipo exerts substantial influence over the development of the Thailand Concession. As of December 31, 2002, the Company s proved reserves located in the Kingdom of Thailand accounted for approximately 24% of the Company s total proved reserves. During 2002, approximately 28% of the Company s natural gas production and 32% of its oil and condensate production came from its operations on the Thailand Concession, contributing approximately 32% of the Company s consolidated oil and gas revenues.

Benchamas Field. In July 1997, the government of Thailand designated a portion of the Thailand Concession comprising approximately 102,000 acres as the Benchamas and Pakakrong production area or the Benchamas Field. Production from the Benchamas Field commenced in July 1999 from three production platforms. In 2002, an additional five platforms were installed. Natural gas and oil from these platforms are delivered by undersea pipeline to a central processing and compression platform where the oil, condensate and natural gas is processed and separated. The natural gas is sold to PTT Public Company Limited (PTT) and delivered into export pipelines for transportation to shore, while the crude oil and condensate produced from the field is stored on board a Floating Storage and Offloading system (FSO) known as the Benchamas Explorer for sale and ultimate transfer to shore by oil tanker. The FSO is moored in the Benchamas Field. Its capacity is approximately 1,400,000 Bbls of crude oil and condensate. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources. Contracts have been signed and steel has been ordered for the construction of at least four additional platforms for this area. Two platforms will be installed during 2003 in the Benchamas Field and additional platforms are scheduled for installation in 2004. Additional exploratory and development drilling is also currently planned for the Benchamas Field during 2003. The temporary shutdown of the Benchamas Field to upgrade the Benchamas central processing platform, which had been scheduled for the first quarter of 2003, has now been postponed until late 2003 or early 2004. The upgrade was delayed to allow delivery of all of the equipment needed for the upgrade and to ensure sufficient planning to minimize the shutdown period. During 2002, 50 wells were drilled in the Benchamas Field, which currently has 98 producing wells (including 19 horizontal wells) and 13 water injection wells.

Tantawan Field. In August 1995, at the request of Thaipo and its joint venture partners, the government of Thailand designated a portion of the Thailand Concession comprising approximately 68,000 acres as the Tantawan production area or the Tantawan Field. Initial production from the Tantawan Field commenced on February 1, 1997. Oil and gas production from the Tantawan Field is gathered through pipelines from the platforms into a Floating Production Storage and Offloading system (an FPSO) named the Tantawan Explorer. The FPSO is a converted oil tanker with a capacity of slightly less than 1,000,000 Bbls, that is moored in the Tantawan Field, on which hydrocarbon processing, separation, dehydration, compression, metering and other production-related equipment is installed. Following processing on board the FPSO, natural gas produced from the field is delivered to PTT through an export pipeline. Oil and condensate produced from the field is stored on board the FPSO until sold and transferred to shore by oil tanker. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources. During 2002, four development and two exploratory wells were drilled in the field. Currently, there are approximately 63 wells producing from five platforms. Current plans call for the installation of another platform in the Tantawan Field during 2003 and for additional development drilling. If and when the adjacent Block 9A is assigned to Thaipo and its joint venture partners (an assignment that has been approved by the Minister of Energy and is awaiting final Parliamentary approval), an additional two exploration wells will be drilled to establish the eastern extent of the Tantawan Field, leading to the possibility of up to an additional two platforms being installed in Block 9A in 2004 if a production license is successfully obtained in a timely manner.

Maliwan Field. In September 1997, the government of Thailand designated an additional approximately 91,000 acres of the Thailand Concession as the Maliwan production area or the Maliwan Field. The Maliwan A platform was installed and commenced production on October 29, 2001. Initial production from this first platform is delivered to the Benchamas Field production handling facilities for processing and sale. Current plans call for additional development and exploration drilling in the Maliwan Field during 2003. In addition, work will continue on finalizing a development plan for the entire field.

Other Portions of the Thailand Concession. Thaipo and its joint venture partners have identified other potentially promising areas on the Thailand Concession and surrounding acreage. In November 2000, approximately 124,000 additional acres of the Thailand Concession, known as the Jarmjuree area, were designated as a production area. Development plans for this area are still being formulated. Two exploration wells were drilled in this production license area during 2002. Up to five more wells could be drilled in the Jarmjuree and surrounding areas during 2003.

During 2002, Thaipo and its joint venture partners drilled a successful exploration well in a portion of the Thailand Concession that is north of the Benchamas Field. On the basis of this successful well and other wells previously drilled in this area that tend to establish a northward extension of the Benchamas Field, another production license, the North Benchamas production license was applied for during the fourth quarter of 2002. Thaipo and its joint venture partners currently anticipate that this production license area, covering up to an additional 31,000 acres, could be granted to the joint venture by the end of 2003. If this is the case, then Thaipo and its joint venture partners currently plan to install a platform in this area and tie it back to the Benchamas Field in late 2004. During 2002, Thaipo and its joint venture partners drilled six exploratory wells and have currently budgeted to drill additional exploratory wells during 2003. Interpretation of the data provided by these wells and 3-D seismic data covering the Thailand Concession is ongoing.

Platforms are installed on the Thailand Concession in fields where, in the judgment of Thaipo and its joint venture partners, the necessary capital expenditures are justified. A decision to install a platform generally is made after the drilling of one or more exploratory wells with contracted drilling equipment and the area where the platform would be located has been designated a production area by the government of the Kingdom of Thailand. See Contractual Terms Governing the Thailand Concession and Related Production. Platforms are used to accommodate both development drilling and additional exploratory drilling. A key focus of Thaipo and its joint venture partners has been to reduce the average cost of the platforms installed to improve the overall economics of the project. The gross cost of the fourteen production platforms and related facilities installed in the Tantawan, Benchamas and Maliwan Fields to date have averaged approximately $17,400,000 per platform. Platform costs vary, and more (or less) expensive platforms could be required in the future depending on, among other factors, the number of slots, water depth, currents and sea floor conditions and the amount of facilities required to be placed on the platform.

Contractual Terms Governing the Thailand Concession and Related Production

The Thailand Concession was granted in August 1991. The initial exploratory term for the Thailand Concession expired on July 31, 2000. However, through a series of one-year extensions, Thaipo and its joint venture partners have been granted an extension of the exploratory term through July 31, 2003. Similar one-year extensions can also be applied for through July 31, 2005. Thaipo and its joint venture partners intend to continue to apply for extensions for areas of the Thailand Concession they believe to be prospective until all of the acreage has been adequately evaluated. For those portions of the Thailand Concession that have been designated as production areas, the initial production period term is 20 years, which is also subject to extension, generally for a term of ten years. In November 2002, Thaipo and its joint venture partners requested that the government designate the North Benchamas area as a production area. To date, the Benchamas Field, Tantawan Field, Maliwan Field and North Jarmjuree areas have been designated as production areas. Subject to governmental approval, other portions of the Thailand Concession may be designated production areas in the future.

Production resulting from the Thailand Concession is subject to a royalty ranging from 5% to 15% of oil and gas sales. In addition, the joint venture partners expect to pay a final production bonus of $7,500,000 ($3,476,000 net to the Company) in the first half of 2003 as a result of averaging at least 100,000 BOE for one calendar month. Profits from production in Thailand are also subject to a Special Remuneration Benefit (SRB). The SRB rate is calculated based on a complex formula using discounted revenue, meters drilled and other factors specified in the Thailand Concession license agreement. This rate is then applied toward the net proceeds derived by each joint venture partner s Thailand subsidiaries. The SRB rates can range from 20% to 75%. SRB payments are then treated as a deductible expense for Thailand income tax calculations by such subsidiaries. The Company currently expects to accrue SRB liabilities in 2003 on a portion of the net proceeds it derives from the Thailand Concession.

Thaipo and its joint venture partners have entered into a thirty-year Gas Sales Agreement with PTT (the Gas Sales Agreement), governing gas production from the Tantawan Field and the Benchamas Field. The terms of the Gas Sales Agreement currently include a minimum daily contract quantity (DCQ) of 125 MMcf per day, subject to certain exceptions and will in the future be based on a percentage of the remaining proved reserves, but in any event, will not be less than 125 MMcf per day. In addition, the Gas Sales Agreement gives PTT the right to nominate in any given week, 115% of DCQ or approximately 145 MMcf per day. Effective October 1, 2001, Thaipo and its joint venture partners amended the Gas Sales Agreement to provide, among other things, that PTT may take up to an additional approximate 58 billion cubic feet of gas through March 1, 2004 at production rates which vary, depending upon the time period, from 26 MMcf up to 85 MMcf per day (Supplemental DCQ) or approximately 12MMcf to 40MMcf net to the Company. During 2002, gas production averaged approximately 192 MMcf per day (89 MMcf per day net to the Company), with production in the fourth quarter averaging 195 MMcf per day (91 MMcf per day net to the Company).

Thaipo and its joint venture partners are subject to certain penalties if they are unable to meet the DCQ or the Supplemental DCQ under the Gas Sales Agreement. Failure to meet DCQ results in a decrease in the sales price for gas sold under the Gas Sales Agreement of up to 25% of the then current sales price and failure to meet the Supplemental DCQ will result in a credit against the next month s supplemental production of 12% of the then current sales price of the gas not delivered. Thaipo currently meets the minimum DCQ and generally meets the Supplemental DCQ requirements, however, there can be no assurance that Thaipo will be able to continue to meet them in the future, in which case these penalty provisions would reduce the price received by Thaipo for its gas sold to PTT under the Gas Sales Agreement.

The sales price for the base DCQ production under the Gas Sales Agreement is subject to automatic semi-annual adjustments based upon a formula that takes into account changes in: Singapore fuel oil prices; the U.S. Bureau of Labor Statistics Oilfield Machinery and Tool Index; the Thai wholesale producer price index; and the U.S./Thai currency exchange rate. However, the Gas Sales Agreement provides for adjustment on a more frequent basis in the event that certain indices and factors on which the price is based fluctuate outside a given range. The sales price for Supplemental DCQ production is 88% of the then current sales price for DCQ production. As of December 31, 2002, the Company was receiving a blended average price of approximately $2.22 per Mcf under the Gas Sales Agreement for DCQ and Supplemental DCQ production. See Management s Discussion and Analysis of

Financial Condition and Results of Operations Results of Operations; Foreign Currency Transaction Gain (Loss) and Liquidity and Capital Resources; Other Matters; Southeast Asia Economic Issues.

Europe Region. On April 20, 1999, the Company s subsidiary Pogo Hungary Ltd. (Pogo Hungary) was awarded a license to explore for oil and gas in the Szolnok and Tompa areas of central and south central Hungary. This license area currently consists of approximately 782,000 acres. The exploration term of the license is currently set to expire on April 19, 2005, unless otherwise extended by the government. Areas where commercial accumulation of hydrocarbons are identified may then be designated as mining plots and held through the economic productive life of such reserves. During 2002, Pogo Hungary interpreted the 2-D and 3-D seismic surveys it acquired during 2000 and 2001. One 3-D survey covers approximately 97,000 acres, a substantial portion of the Tompa area, and the other covers approximately 42,000 acres of the Szolnok area and is referred to as the Kenderes 3-D survey. Based upon their detailed evaluation of this 3-D seismic data and extensive other data acquired from government sources, a number of prospects have been preliminarily identified. Assuming that the necessary permits and other government and regulatory approvals and assurances are obtained in a timely manner, Pogo Hungary has budgeted to drill approximately six wells during the second half of 2003 to evaluate six prospective play types on its Tompa and Szolnok areas. Three of the potential drilling locations are currently located in the Tompa area and the other three are located in the Szolnok area.

Hungary imported approximately 70% of the crude oil and approximately 74% of the natural gas that it consumed in 2001. Most of the crude oil and the natural gas that is imported into Hungary comes from Russia. The remaining imported natural gas is delivered from Austria through the Baumgarten hub. Historically, the domestic Hungarian oil and gas industry was entirely state-owned. Following privatization of the industry during the 1990s, the wholesale and retail prices for natural gas remained heavily regulated and partially subsidized. The Hungarian retail petroleum market was liberalized in 1991. Currently, the Company believes that crude oil produced in Hungary may be sold in Hungary or exported at a price based upon world market prices. The sale of natural gas in Hungary is still subject to pricing regulation under the existing Hungarian Natural Gas Act which currently restricts the wholesale price of natural gas sold in Hungary to a range of approximately $3.19 to $5.21 per Mcf, depending on the end user. However, in connection with its ascension to the European Union, Hungary is obligated to liberalize its gas market and to remove price controls on at least a portion of its domestic natural gas market. The Hungarian government is currently formulating modifications to the Natural Gas Act that will comply with applicable European Union directives on market liberalization. Alternatively, the Company currently believes that it will be able to swap gas it produces in Hungary for gas at the Baumgarten hub, which can then be sold at unregulated European spot prices.

On August 5, 1999, the Danish government approved the assignment to the Company of a 40% working interest in License 13/98 covering approximately 81,000 acres in the Danish sector of the North Sea. This license interest is currently held by the Company s Danish subsidiary, Pogo Denmark ApS. The work commitment for this license requires the drilling of an exploratory well prior to the expiration of the license. The initial term of the license goes through June 14, 2004, unless otherwise extended or a production license is granted. Pogo Denmark ApS and its joint venture partners are reprocessing and reinterpreting an existing 3-D seismic survey and currently intend to drill a well during 2003 on one of the prospects that has been identified on the block.

Pogo North Sea Limited, a British subsidiary of the Company, together with two joint venture partners, also holds a license governing approximately 113,000 acres in the British sector of the North Sea. A possible prospect has been identified on the block, based upon recently acquired 3-D seismic data, that may require the joint venture to drill a well on the license prior to its expiration. Discussions are currently ongoing between the joint venture and the government regarding evaluation of this prospect. The current exploratory term of this license expires on December 1, 2004, unless otherwise extended or a production license is granted.

Miscellaneous

Other Assets

The Company and a subsidiary, Pogo Offshore Pipeline Co., own interests in eight pipelines (excluding field gathering pipelines) through which offshore hydrocarbon production is transported. As previously discussed, the Company also owns an approximate 12.4% interest in the Lost Cabin Gas Plant located in the Madden Field, which currently has the capacity to process 312 MMcf of natural gas per day. During 2002, the Company successfully divested an approximate 19% interest of a cryogenic gas processing plant near Erath, Louisiana for approximately $3,900,000. As part of the Company s ongoing efforts to focus on its core business of finding and producing oil and natural gas, the Company is exploring sales opportunities for its interest in other non-core assets if a favorable price can be obtained. The Company does not currently expect that the sale of any or all of these non-core assets would have a substantial material impact on the Company s business or operations, taken as a whole.

Sales

The marketing of all of the Company s onshore and offshore oil and gas production is subject to the availability of pipelines and other transportation, processing and refining facilities, as well as the existence of adequate markets. As a result, even if hydrocarbons are discovered in commercial quantities, a substantial period of time could elapse before commercial production commences. If pipeline facilities in an area are insufficient, the Company may have to await the construction or expansion of pipeline capacity before production from that area can be marketed. The Company s domestic onshore and offshore properties are generally located in areas where a pipeline infrastructure or other transportation alternatives are well developed and there is adequate availability in such pipelines or other transportation alternatives to transport the Company s current and projected future production.

The Company may not be able to successfully market all of the oil and natural gas found and produced on the Thailand Concession. Currently, the only purchaser of natural gas is PTT, which maintains a monopoly over gas transmission and distribution in Thailand, including ownership of the two major (34 inches and 36 inches in diameter, respectively) natural gas pipelines that traverse the Thailand Concession. All oil and condensate production from the Tantawan Field is initially stored aboard the FPSO and then sold to various third parties, including PTT, on a tanker load by tanker load basis at prices based on then current world oil prices, typically with reference to the Malaysian Tapis Blend crude oil benchmark price. Crude oil and condensate production from the Benchamas Field and the first platform located in the northern portion of the Maliwan Field is initially stored aboard the FSO. A portion of this production is sold under a term sale agreement with United Petroleum & Chemicals Company Limited that expires in May 2003. This term sale agreement is for a total of 6,000,000 Bbls (2,780,000 Bbls net to Thaipo) at a price equal to Malaysian TAPIS less $0.55 per Bbl. The remaining production from the Benchamas Field is sold on a tanker load by tanker load basis, similar to the way Tantawan Field crude oil is currently marketed.

The prices that the Company receives for crude oil sales from our Thailand Concession are influenced by a number of factors including, among others, tanker availability, world-wide crude oil demand, size of the lifting and the perceived quality of crude oil produced. For example, crude oil produced from the Gulf of Thailand is generally perceived as having high mercury levels. The crude oil from the Benchamas Field has high wax content. Therefore, it is sought after by some refineries and is less desirable to others. These factors and others have led to significant fluctuations in the price that the Company receives for its Thai crude oil production in comparison to the Malaysian Tapis Blend benchmark price. During 2002, the price that the Company received for its crude oil production from the Thailand Concession ranged between a $1.10 per Bbl premium and a $1.05 per Bbl discount to the Malaysian Tapis Blend benchmark price. The Company and its joint venture partners continue to examine ways to improve the price received for crude oil, including the possibility of entering into long-term contracts for a portion of its production, although none of its production is currently committed to such an arrangement. In addition, because much of the oil produced from the Thailand Concession is associated with natural gas, limitations on Thaipo s ability to produce natural gas could limit crude oil production as well. The crude oil purchaser is generally responsible for sending a tanker to offload the oil and condensate it has purchased. See International Operations; Contractual Terms Governing the Thailand Concession and Related Production.

Most of the Company s North American natural gas sales (exclusive of forward gas sales contracts) are currently made in the spot market for no more than one month at a time at then currently available prices or under longer-term contracts with prices that are based on, and fluctuate with, spot market prices. Prices on the spot market fluctuate with supply and demand. Crude oil and condensate production is also generally sold one month at a time at the price that is then currently available or under longer-term contracts with prices that also fluctuate in relationship to published market price. Other than any oil and natural gas forward sales contracts that may exist from time to time, and are referred to in Miscellaneous; Competition and Market Conditions, and the Gas Sales Agreement with PTT for production from the Thailand Concession (see International Operations; Contractual Terms Governing the Thailand Concession and Related Production), the Company has no existing contracts that require the delivery of fixed quantities of oil or natural gas, other than on a best efforts basis. No customer in 2002 constituted more than 10% of the Company s consolidated revenues.

Risks Associated with Acquisitions

From time to time the Company acquires, and may acquire in the future, additional interests in oil and gas properties, either through acquisition of the properties themselves or, as in the case of the Arch and North Central acquisitions, indirectly through the purchase of an equity interest in the entity owning such properties. The successful acquisition of such properties requires an assessment of several factors, including recoverable reserves, projected future cash flows that are, in part, based upon future oil and gas prices, current and projected operating, general and administrative and other costs, and contingent liabilities associated with the properties or entities acquired, including potential environmental and other liabilities.

The accuracy of the Company s assessment of these factors is inherently uncertain. To the extent reasonably practicable under the specific circumstances of each acquisition, the Company performs a review of the properties or entities prior to an acquisition. The Company believes that its review procedures are generally consistent with current industry practices. The Company s review and assessment process will not reveal all existing or potential problems nor will it permit the Company to become sufficiently familiar with the properties or entities to fully assess their deficiencies and capabilities. Even when problems are identified, the other party may be unwilling or unable to provide effective contractual protection against all or part of the problems. The Company is generally not entitled to contractual indemnification for many liabilities, acquiring the properties on an as is, where is basis. In addition, successful acquisitions frequently require the successful integration of operations, equipment and, in the case of indirect acquisitions, personnel. There can be no assurance that the Company will be able to successfully integrate operations and properties that it acquires and still achieve the anticipated synergies, cost savings and efficiencies.

Competition and Market Conditions

The Company experiences competition from other oil and gas companies in all phases of its operations, as well as competition from other energy related industries. The Company s profitability and cash flow are highly dependent upon the prices of oil and natural gas, which historically have been seasonal, cyclical and volatile. In general, prices of oil and gas are dependent upon numerous factors beyond the control of the Company, including various weather, economic, political and regulatory conditions. In addition, the decisions of the Organization of Petroleum Exporting Countries relating to export quotas also affect the price of crude oil. A future drop in oil or gas prices could have a material adverse effect on the Company s cash flow and profitability. Sustained periods of low prices could cause the Company to shut in existing production and also have a material adverse effect on its operations and financial condition. It could also result in a reduction of funds available under the Company s bank credit facilities. See Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources; Credit Facility.

Because it is impossible to predict future oil and gas price movements with any certainty, the Company from time to time enters into contracts to hedge against future market price changes on a portion of its production. Such hedging transactions, historically, have never exceeded 50% of the Company s total oil and gas production on an energy equivalent basis for any given period. While intended to limit the negative effect of price declines, some forms of hedging transactions could effectively limit the Company s participation in price increases, which could be significant, for the covered period. As of December 31, 2002, the Company was a party to the natural gas and crude oil option contracts described in Quantitative and Qualitative Disclosure About Market Risk. When the Company does engage in certain types of hedging activities, it may satisfy its obligations with its own production or by the purchase (or sale) of third-party production. The Company may also offset delivery obligations under these hedging transactions requiring physical delivery with equivalent agreements, thereby effecting a purely cash transaction.

Operating and Uninsured Risks

The Company s operations are subject to risks inherent in the exploration for and production of oil and natural gas, such as blowouts, cratering, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pollution and other environmental risks. Offshore oil and gas operations are subject to the additional hazards of marine and helicopter operations, such as capsizing, collision and adverse weather and sea conditions. These hazards could result in substantial losses to the Company due to injury or loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations. The Company carries insurance that it believes is in accordance with customary industry practices, but is not fully insured against all risks incident to its business.

Drilling activities are subject to numerous risks, including the risk that no commercially productive hydrocarbon reserves will be encountered. The cost of drilling, completing and operating wells and of installing production facilities and pipelines is often uncertain. The Company s drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including title problems, weather conditions, compliance with governmental requirements and shortages or delays in the delivery or availability of material, equipment and fabrication yards. In periods of increased drilling activity resulting from high commodity prices, demand exceeds availability for drilling rigs, drilling vessels, supply boats and personnel experienced in the oil and gas industry in general, and the offshore oil and gas industry in particular. This may lead to difficulty and delays in consistently obtaining certain services and equipment from vendors, obtaining drilling rigs and other equipment at favorable rates and scheduling equipment fabrication at factories and fabrication yards. This in turn may lead to projects being delayed or experiencing increased costs.

In periods during which the industry experiences a substantial decline in oil and gas prices, many of the Company s partners, particularly the smaller ones, can experience liquidity and cash flow problems. These problems may lead to the smaller companies attempts to delay or slow down the pace of drilling or project development in order to conserve cash, to a point that the Company believes is detrimental to the project. In most cases, the Company has the ability to influence the pace of development through joint operating agreements. Some partners may be unwilling or unable to pay their share of the costs of projects as they become due. At worst, a partner may declare bankruptcy and refuse or be unable to pay its share of the costs of a project. The Company would then be required to pay this partner s share of the project costs. In most instances, the Company believes that it is contractually protected from such an event through its ability to take over the non-paying partner s share of the project and by applicable oil and gas lien laws and bankruptcy laws. The Company believes that it would ultimately recover any sums that it is owed by non-paying partners that do not meet their share of the costs of a project in a timely fashion.

Risks of Foreign Operations

Ownership of property interests and production operations in Thailand, Hungary, the North Sea and in any other areas outside the United States in which the Company may choose to do business are subject to the various risks inherent in foreign operations. These risks may include, among other things, currency restrictions and exchange rate fluctuations, loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, war, insurrection and other political risks, risks of increases in taxes and governmental royalties, renegotiation of contracts with governmental entities, changes in laws and policies governing operations of foreign-based companies and other uncertainties arising out of foreign government sovereignty over the Company s international operations. See Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations; Foreign Currency Transaction Gain (Loss), and Liquidity and Capital Resources; Other Matters; Southeast Asia Economic Issues. The Company s international operations may also be adversely affected by laws and policies of the United States affecting foreign trade, taxation and investment. In addition, in the event of a dispute arising from foreign operations, the Company may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts of the United States. The Company seeks to manage these risks by concentrating its international exploration efforts in areas where the Company believes that the existing government is stable and favorably disposed towards United States exploration and production companies.

Exploration and Production Data

In the following data, gross refers to the total acres or wells in which the Company has an interest and net refers to gross acres or wells multiplied by the percentage working interest owned by the Company.

Acreage

The Company owns interests in developed and undeveloped oil and gas acreage in various parts of the world. These ownership interests generally take the form of working interests in oil and gas leases that have varying terms. The following table shows the Company s interest in developed and undeveloped oil and gas acreage under lease as of December 31, 2002:

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross	Net	Gross	Net
Domestic Offshore				
Louisiana	144,234	47,896	85,130	57,764
Texas	17,280	6,141	23,040	5,904
Total Domestic Offshore	161,514	54,037	108,170	63,668
Domestic Onshore				
Louisiana	10,475	2,819	10,188	4,790
New Mexico	53,655	39,861	73,821	57,579
Texas	105,261	47,231	89,778	63,564
Wyoming	29,205	3,700	36,548	6,221
Other	6,120	2,211	80	15
Total Domestic Onshore	204,715	95,822	210,415	132,169
Total Domestic	366,229	149,859	318,584	195,837
International				
Gulf of Thailand	385,035	178,431	329,018	152,471
North Sea	0	0	193,631	77,453
Hungary	0	0	781,771	781,771
Total International	385,035	178,431	1,304,420	1,011,695
Total Company	751,264	328,290	1,623,004	1,207,532

(a) Developed acreage consists of lease acres spaced or assignable to production (including acreage held by production) on which wells have been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas. Developed acreage in Thailand includes all acreage designated as a production area by the Thai government, which currently includes Benchamas, Tantawan, Maliwan and Jarmjuree production licenses.

(b) Approximately 2% of the Company s total domestic offshore net undeveloped acreage is under leases that have minimum terms expiring in 2003 and another 5% expires in 2004. Approximately 18% of the Company s total domestic onshore net undeveloped acreage is under leases with minimum terms expiring in 2003 and another 18% expires in 2004. All of the Company s undeveloped acreage in the Kingdom of Thailand is subject to one-year lease extensions that may be applied for each year through July 2005. See International Operations; Contractual Terms Governing the Thailand Concession and Related Production.

In addition, the Company holds certain other types of mineral interests, including fee interests (which never expire) and royalty interests (which generally terminate when the underlying mineral lease expires). The Company owns varying fee and royalty interests in approximately 1,190,600 gross acres (26,875 net acres) in various parts of the United States, principally as a result of the North Central acquisition.

Average Production (Lifting) Costs per Unit of Production

The following table shows the average production (lifting) costs per unit of production during the periods indicated. For a discussion of the Company s average daily production and the average sales prices received by the Company for such production see Selected Financial Data Production (Sales) Data and Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations; Oil and Gas Revenues.

	2002	2001	2000
Average Production (Lifting) Costs per Mcfe (a):			
Located in the United States	$ 0.67	$ 0.81	$ 0.82
Located in the Kingdom of Thailand	$ 0.59	$ 0.65	$ 0.69
Total Company	$ 0.65	$ 0.75	$ 0.77

(a) Production costs were converted to common units of measure on the basis of relative energy content. Such production costs exclude all depletion, depreciation and amortization associated with property and equipment. The Company s operations in Canada were sold effective August 31, 2001 as part of an asset rationalization process. Average production (lifting) costs in Canada, prior to its sale, were $1.37 in 2001 and $0.88 in 2000.

13

Productive Wells and Drilling Activity

The following table shows the Company s interest in productive oil and natural gas wells as of December 31, 2002. For purposes of this table productive wells are defined as wells producing hydrocarbons and wells capable of production (e.g., natural gas wells waiting for pipeline connections or necessary governmental certification to commence deliveries and oil wells waiting to be connected to currently installed production facilities). Net wells for purposes of this table are defined to mean the Company s working interest net of royalties and other burdens. This table does not include exploratory or developmental wells which have located commercial quantities of oil or natural gas but which are not capable of commercial production without the installation of material production facilities or which, for a variety of reasons, the Company does not currently believe will be placed on production.

	Oil Wells (a)(b)		Natural Gas Wells (a)(b)	
	Gross	**Net**	**Gross**	**Net**
Domestic Offshore	168	49.2	80	21.3
Domestic Onshore	747	559.8	590	282.5
Kingdom of Thailand	74	34.3	61	28.3
Total	989	643.3	731	332.1

(a) One or more completions in the same bore hole are counted as one well. The data in the above table includes 17 gross (5.8 net) oil wells and 5 gross (1.9 net) natural gas wells with multiple completions.

(b) The Company was in the process of drilling a total of 4 gross (.34 net) oil wells and 14 gross (7.61 net) natural gas wells as of December 31, 2002.

The following table shows the number of successful gross and net exploratory and development wells in which the Company has participated and the number of gross and net wells abandoned as dry holes during the periods indicated. An onshore well is considered successful upon the installation of permanent equipment for the production of hydrocarbons or when electric logs run to evaluate such wells indicate the presence of commercially producible hydrocarbons and the Company currently intends to complete such wells. Successful offshore wells consist of exploratory or development wells that have been completed or are suspended pending completion (which has been determined to be feasible and economic) and exploratory test wells that were not intended to be completed and that encountered commercially producible hydrocarbons. A well is considered a dry hole upon reporting of permanent abandonment to the appropriate agency.

	2002		2001		2000	
	Productive	**Dry**	**Productive**	**Dry**	**Productive**	**Dry**
Gross Wells:						
Offshore United States						
Exploratory	5.0	2.0	2.0	3.0	4.0	5.0
Development	13.0		22.0		23.0	3.0
Onshore United States and Canada (a)						
Exploratory	1.0	4.0	7.0	3.0	14.0	5.0

Development	83.0	5.0	61.0	3.0	39.0	
Offshore Kingdom of Thailand						
Exploratory	6.0		11.0		7.0	3.0
Development	51.0	2.0	18.0		24.0	
Total	159.0	13.0	121.0	9.0	111.0	16.0
Net Wells:						
Offshore United States						
Exploratory	5.0	2.0	2.0	1.7	2.2	2.4
Development	8.8		8.3		6.2	1.0
Onshore United States and Canada (a)						
Exploratory	0.8	3.2	5.0	1.3	3.8	2.5
Development	54.7	3.4	38.0	1.6	28.1	
Offshore Kingdom of Thailand						
Exploratory	2.8		5.1		3.2	1.4
Development	23.5	0.9	8.3		11.1	
Total	95.6	9.5	66.7	4.6	54.6	7.3

(a) The Company s operations in Canada were sold effective August 31, 2001 as part of an asset rationalization program. Wells drilled in 2000 and 2001 reflect wells drilled in Canada by the Company prior to the sale of these operations.

Reserves

The following table sets forth information as to the Company s net proved and proved developed reserves as of December 31, 2002, 2001 and 2000, and the present value as of such dates (based on an annual discount rate of 10%) of the estimated future net revenues from the production and sale of those reserves, as set forth in reports prepared by Ryder Scott Company L.P. (Ryder Scott) and Miller & Lents, Ltd. (Miller & Lents), the Company s independent petroleum engineers, in accordance with criteria prescribed by the Commission.

The Company does not currently believe that the calculation of estimated future net revenues using the assumptions prescribed by Commission guidelines and generally described below is representative of the true value of future net revenues from the Company s proved reserves. The future prices received by the Company for the sales of its production may be higher or lower than the prices used in calculating the estimates of future net revenues, and the operating costs and other costs relating to such production may also increase or decrease from existing levels.

	As of December 31,		
	2002	2001	2000
Total Proved Reserves:			
Oil, condensate and natural gas liquids (MBbls)			
Located in the United States and Canada (a)	80,092	79,979	58,257
Located in the Kingdom of Thailand	38,087	39,301	37,065
Total Company	118,179	119,280	95,322
Natural Gas (MMcf)			
Located in the United States and Canada (a)	713,906	670,567	216,679
Located in the Kingdom of Thailand	159,604	148,225	153,304
Total Company	873,510	818,792	369,983
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in the United States and Canada (a)	$ 2,495,558	$ 1,130,353	$ 1,948,895
Located in the Kingdom of Thailand	602,798	410,307	506,021
Total Company	$ 3,098,356	$ 1,540,660	$ 2,454,916
Total Proved Developed Reserves:			
Oil, condensate and natural gas liquids (MBbls)			
Located in the United States and Canada (a)	74,041	59,383	35,910
Located in the Kingdom of Thailand	23,832	20,394	24,747
Total Company	97,873	79,777	60,657
Natural Gas (MMcf)			
Located in the United States and Canada (a)	600,255	532,348	152,742

Located in the Kingdom of Thailand	87,301	69,997	87,236
Total Company	687,556	602,345	239,978
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in the United States and Canada (a)	$ 2,239,781	$ 951,040	$ 1,246,068
Located in the Kingdom of Thailand	422,219	241,860	445,033
Total Company	$ 2,662,000	$ 1,192,900	$ 1,691,101

(a) The Company sold its operations and reserves in Canada effective August 31, 2001 as part of an asset rationalization process. Consequently, year-end 2002 and 2001 reserves, and the present value of future net revenues for those reserves, do not include any reserves located in Canada.

The Company believes, for the reasons set forth in succeeding paragraphs, that the present value of estimated future net revenues set forth in the Annual Report and calculated in accordance with Commission guidelines is not necessarily indicative of the true fair value of the Company s reserves. Moreover, due to the fact that essentially all of the Company s domestic natural gas production is currently sold on the spot market, while all of the Company s Thailand natural gas production is sold pursuant to a long-term gas sales contract, the estimates of future net revenues from the Company s domestic and Thailand reserves are of limited value for comparative purposes.

Natural gas liquids comprised approximately 6% of the Company s total proved liquids reserves and approximately 6% of the Company s proved developed liquids reserves as of December 31, 2002. All hydrocarbon liquid reserves are expressed in standard 42 gallon Bbls. All gas volumes and gas sales are expressed in MMcf at the pressure and temperature bases of the area where the gas reserves are located.

In accordance with Commission guidelines, the prices used by the Company to calculate the present value of estimated future revenues are determined on a well or field-by-field basis, as applicable, as described above and were held constant over the productive life of the reserves. The initial weighted average prices used by Ryder Scott and Miller & Lents were as follows:

	As of December 31,		
	2002	**2001**	**2000**
Initial Weighted Average Price (in Dollars):			
Oil, condensate and natural gas liquids (per Bbl)			
Located in the United States and Canada (a)	$ 28.72	$ 18.75	$ 26.10
Located in the Kingdom of Thailand	$ 32.41	$ 18.94	$ 24.23
Natural Gas (per Mcf)			
Located in the United States and Canada (a)	$ 4.70	$ 2.48	$ 10.14
Located in the Kingdom of Thailand	$ 2.24	$ 2.31	$ 2.27

(a) The Company sold its operations and reserves in Canada effective August 31, 2001 as part of an asset rationalization process. Consequently, average price figures do not include Canada sales for the last five months of 2001 and all of 2002.

In computing future revenues from gas reserves attributable to the Company s domestic interests, prices in effect at December 31, 2002 were used, including current market prices, contract prices and fixed and determinable price escalations where applicable. In accordance with Commission guidelines, the gas prices that were used make no allowances for seasonal variations in gas prices that are likely to cause future yearly average gas prices to be different than December gas prices. For domestic gas sold under contract, the contract gas price including fixed and determinable escalations, exclusive of inflation adjustments, was used until the contract expires and then was adjusted to the current market price for the area and held at this adjusted price to depletion of the reserves. In computing future revenues from liquids attributable to the Company s domestic interests, prices in effect at December 31, 2002 were used and these prices were held constant to depletion of the properties. The future net revenues are adjusted to reflect the Company s net revenue interest in these reserves as well as any ad valorem and other severance taxes but do not include any provisions for corporate income taxes.

In computing future revenues from the Company s gas reserves attributable to the Company s interests in the Kingdom of Thailand, a blended price that took into account the current contract price under the Gas Sales Agreement for the base production (currently 145 MMcf per day) and the price for excess sales volumes (which varies depending on the period and the nomination) was used, without giving effect to any of the future adjustments provided for in the Gas Sales Agreement, due to their indeterminate nature as of December 31, 2002, in accordance with Commission guidelines. In computing future revenues from liquids attributable to the Company s interests in the Kingdom of Thailand, a price was used that the Company believes approximates the price that the Company would have received for its production from the Thailand Concession based upon the world market price for Malaysian Tapis Blend benchmark crude on December 31, 2002, and this price was held constant until depletion of the Company s reserves in the Kingdom of Thailand. The future net revenues are adjusted to reflect the Company s net revenue interest in these reserves and the Company s obligations under the Thailand Concession, including the payment of SRB and applicable production bonuses, but do not include any provisions for U.S. or Thai corporate income or other taxes.

In accordance with Commission guidelines for calculating future net revenues, the operating costs for the leases and wells include only those costs directly applicable to the leases or wells. When applicable, the operating costs include a portion of general and administrative costs allocated directly to the leases and wells under terms of operating agreements. Development costs are based on authorization for expenditure for the proposed work or actual costs for similar projects. The current operating and development costs were held constant throughout the life of the properties. The estimated net cost of abandonment after salvage was considered for the properties. No deduction was made for indirect costs such as general and administrative and overhead expenses, loan repayments, interest expenses and exploration and development prepayments. Accumulated gas production imbalances, if any, have been taken into account.

Production data used to arrive at the estimates set forth above includes estimated production for the last few months of 2002. The future production rates from reservoirs now on production may be more or less than estimated because of, among other reasons, mechanical breakdowns and changes in market demand or allowables set by regulatory bodies. Properties that are not currently producing may start producing earlier or later than anticipated in the estimates of future production rates.

There are numerous uncertainties in estimating the quantity of proved reserves and in projecting the future rates of production and timing of development expenditures. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way, and estimates of other engineers might differ materially from those of the Company, Ryder Scott and Miller & Lents. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate, which may be material. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered.

The Company is periodically required to file estimates of its oil and gas reserve data with various U.S. governmental regulatory authorities and agencies, including the Department of Energy, the Federal Energy Regulatory Commission (FERC) and the Federal Trade Commission and, with respect to reserves located in Thailand, the Kingdom of Thailand s Department of Mineral Resources and PTT, which the Company considers a quasi-governmental authority. In addition, estimates are from time to time furnished to governmental agencies in connection with specific matters pending before such agencies. The basis for reporting reserves to these agencies, in some cases, is not comparable to that furnished by Ryder Scott and by Miller & Lents in accordance with Commission guidelines because of the nature of the various reports required. The major differences generally include differences in the time as of which such estimates are made, differences in the definition of reserves, requirements to report in some instances on a gross, net or total operator basis and requirements to report in terms of smaller geographical units. During 2002, no estimates by the Company of its total proved net oil and gas reserves were filed with or included in reports to any governmental authority or agency other than the Commission.

Government Regulations

Federal Income Tax

Federal income tax laws significantly affect the Company s operations. The principal provisions affecting the Company are those that permit the Company, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, its domestic intangible drilling and development costs and to claim depletion on a portion of its domestic oil and gas properties based on 15% of its oil and gas gross income from such properties (up to an aggregate of 1,000 Bbls per day of domestic crude oil and/or equivalent units of domestic natural gas), even though the Company has little or no basis in such properties. Under certain circumstances, however, a portion of such intangible drilling and development costs and the percentage depletion allowed in excess of basis will be tax preference items that will be taken into account in computing the Company s alternative minimum tax. In addition, the Company currently has substantial net operating loss carryforwards, principally related to its operations in Thailand, that are available to offset the Company s future taxable income. The Company currently expects to utilize the majority of these net operating loss carryforwards in the next two years.

Environmental Matters

Domestic oil and gas operations are subject to extensive federal regulation and, with respect to federal leases, to interruption or termination by governmental authorities on account of environmental and other considerations such as the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) also known as the Superfund Law. The trend towards stricter standards in environmental legislation and regulation could increase costs to the Company and others in the industry. Oil and gas lessees are subject to liability for the costs of clean-up of pollution resulting from a lessee s operations, and may also be subject to liability for pollution damages. The Company maintains insurance against costs of clean-up operations, but is not fully insured against all such risks. A serious incident of pollution may, as it has in the past, also result in the Department of the Interior requiring lessees under federal leases to suspend or cease operation in the affected area.

The operators of the Company s properties have numerous applications pending before the Environmental Protection Agency (the EPA) for National Pollution Discharge Elimination System (NPDES) water discharge permits with respect to offshore drilling and production operations. NPDES permits are required to ensure that effluent discharges from each facility or installation comply with the applicable federal regulations.

The Oil Pollution Act of 1990 (the OPA) and regulations thereunder impose a variety of regulations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of federal safety, construction or operating regulations. Few defenses exist to the liability imposed by the OPA. In addition, to the extent the Company s offshore lease operations affect state waters, the Company may be subject to additional state and local clean-up requirements or incur liability under state and local laws.

The OPA also imposes ongoing requirements on responsible parties, including proof of financial responsibility to cover at least some costs in a potential spill. The amount of financial responsibility that the Company must currently demonstrate for its offshore platforms is $70,000,000. The Company believes that it currently has established adequate proof of financial responsibility for its offshore facilities at no significant increase in expense over recent prior years. However, the Company cannot predict whether these financial responsibility requirements under the OPA amendments will result in the imposition of substantial additional annual costs to the Company in the future or otherwise materially adversely affect the Company. The impact, however, should not be any more adverse to the Company than it will be to other similarly situated or less capitalized owners or operators in the Gulf of Mexico.

The Company s onshore operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment including CERCLA. Such laws and regulations, among other things, impose absolute liability on the lessee for the cost of clean-up of pollution resulting from a lessee s operations, subject the lessee to liability for pollution damages, may require suspension or cessation of operations in affected areas, and impose restrictions on the injection of liquids into subsurface aquifers that may contaminate groundwater. Such laws could have a significant impact on the operating costs of the Company, as well as the oil and gas industry in general. Federal, state and local initiatives to further regulate the disposal of oil and gas wastes are also pending in certain jurisdictions, and these initiatives could have a similar impact on the Company. The Company s operations are also subject to additional federal, state and local laws and regulations relating to protection of human health, natural resources, and the environment pursuant to which the Company may incur compliance costs or other liabilities.

The Company is asked to comment on the costs it incurred during the prior year on capital expenditures for environmental control facilities and the amount it anticipates incurring during the coming year. The Company believes that, in the course of conducting its oil and gas operations, many of the costs attributable to environmental control facilities would have been incurred absent environmental regulations as prudent, safe oilfield practice. During 2002, the Company incurred capital expenditures of approximately $2,211,000 for environmental control facilities, primarily relating to the cost of installing environmental equipment on the Company s Main Pass Blocks 61/62 Field B platform and five new Benchamas platforms, the conversion of two wells to salt water disposal wells, the installation of pit and firewall spill liners, and routine site restoration costs. The Company has budgeted approximately $1,592,000 for expenditures involving environmental control facilities during 2003, including, among other things, anticipated site restoration costs and the installation of environmental control equipment.

Other Laws and Regulations

Various laws and regulations often require permits for drilling wells and also cover spacing of wells, the prevention of waste of oil and gas including maintenance of certain gas/oil ratios, rates of production and other matters. The effect of these laws and regulations, as well as other regulations that could be promulgated by the jurisdictions in which the Company has production, could be to limit the number of wells that could be drilled on the Company s properties and to limit the allowable production from the successful wells completed on the Company s properties, thereby limiting the Company s revenues.

The MMS administers the oil and gas leases held by the Company on federal onshore lands and offshore tracts in the Outer Continental Shelf. The MMS holds a royalty interest in these federal leases on behalf of the federal government. While the royalty interest percentage is fixed at the time that the lease is entered into, from time to time the MMS changes or reinterprets the applicable regulations governing its royalty interests, and such action can indirectly affect the actual royalty obligation that the Company is required to pay. However, the Company believes that the impact of the regulations generally do not impact the Company to any greater extent than other similarly situated producers.

The FERC has embarked on wide-ranging regulatory initiatives relating to gas transportation rates and services, including the availability of market-based and other alternative rate mechanisms to pipelines for transmission and storage services. In addition, the FERC has announced and implemented a policy allowing pipelines and transportation customers to negotiate rates above the otherwise applicable maximum lawful cost-based rates on the condition that the pipelines alternatively offer so-called recourse rates equal to the maximum lawful cost-based rates. With respect to gathering services, the FERC has issued orders declaring that certain facilities owned by interstate pipelines primarily perform a gathering function, and may be transferred to affiliated and non-affiliated entities that are not subject to the FERC s rate jurisdiction. The Company cannot predict the ultimate outcome of these developments, or the effect of these developments on transportation rates. Inasmuch as the rates for these pipeline services can affect the gas prices received by the Company for the sale of its production, the FERC s actions may have an impact on the Company. However, the impact should not be substantially different on the Company than it will on other similarly situated gas producers and sellers.

Employees

As of December 31, 2002, the Company and its subsidiaries had 219 full-time employees, including seven in its Bangkok, Thailand office and four in its Budapest, Hungary office. None of the Company s employees are presently represented by a union for collective bargaining purposes. The Company considers its relations with its employees to be generally excellent.

Available Information

The Company files annual, quarterly and current reports, proxy statements and other information with the Commission. These filings are available free of charge through our internet website at www.pogoproducing.com as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Commission.

ITEM 2. ***Properties.***

The information appearing in Item 1 of this Annual Report is incorporated herein by reference.

ITEM 3. ***Legal Proceedings.***

The Company is a party to various legal proceedings consisting of routine litigation incidental to its businesses, but believes that any potential liabilities resulting from these proceedings are adequately covered by insurance or are otherwise immaterial at this time. See Business Government Regulation; Other Laws and Regulations.

ITEM 4. ***Submission of Matters to a Vote of Security-Holders.***

Not Applicable.

ITEM S-K 401(b). ***Executive Officers of Registrant.***

Officers of the Company are appointed annually by the Company s Board of Directors to serve for the ensuing year or until their successors have been elected or appointed. The officers of the Company that have been designated as executive officers for purposes of Item 401(b) of Regulation S-K and officers for purposes of Section 16 of the Exchange Act, their age as of December 31, 2002, and the year each was elected to his current position are as follows:

Executive Officer	Executive Office	Age	Year Elected
Paul G. Van Wagenen	Chairman, President and Chief Executive Officer	56	1991
Stephen R. Brunner	Executive Vice President Operations	44	2002
Stuart P. Burbach	Executive Vice President Exploration	50	1998
Jerry A. Cooper	Executive Vice President and Regional Manager Western United States	54	2002
John O. McCoy, Jr.	Executive Vice President and Chief Administrative Officer	51	2002
David R. Beathard	Senior Vice President Engineering	44	2002
Gerald A. Morton	Senior Vice President and Regional Manager Asia and Pacific	44	2003
James P. Ulm, II	Senior Vice President and Chief Financial Officer	39	2002
Thomas E. Hart	Vice President and Chief Accounting Officer	59	1999
Michael J. Killelea	Vice President and General Counsel	40	2001

Mr. Van Wagenen, who joined the Company in 1979, has served in his current position since 1991. Prior to assuming their present positions with the Company, the business experience of each of the other executive officers for more than the last five years was as follows: Mr. Brunner, who joined the Company in 1994, served as Vice President Operations since 1997; Mr. Burbach served as Vice President and Offshore Division Manager since rejoining the Company in 1991; Mr. Cooper, who joined the Company in 1979, served as Senior Vice President and Western Division Manager since 1998 and prior thereto, served as Vice President and Western Division Manager since 1990; Mr. McCoy, who joined the Company in 1978, served as Senior Vice President and Chief Administrative Officer of the Company since 1998 and as Vice President and Chief Administrative Officer since 1989; Mr. Beathard, who joined the Company in 1982, served as Vice President Engineering since 1997; Mr. Morton, who joined the Company in 1993, served as Vice President and Regional Manager Asia and Pacific since

2002, Vice President Law, Chief Regulatory Officer and Corporate Secretary since 2001, and prior thereto was Vice President Law and Corporate Secretary since 1997; Mr. Ulm served as Treasurer of Newfield Exploration Company from 1995 until joining the Company as its Vice President and Chief Financial Officer in 1999; Mr. Hart joined the Company in 1977 and served as Vice President and Controller since 1988; and Mr. Killelea was Chief Counsel of the Company since he joined the Company in 2000 and prior thereto served as Chief Counsel of CMS Oil and Gas Company for more than three years.

PART II

ITEM 5. ***Market for the Registrant s Common Equity and Related Stockholder Matters.***

The following table shows the range of low and high sales prices of the Company s Common Stock (the Common Stock) on the New York Stock Exchange composite tape where the Common Stock trades under the symbol PPP. The Common Stock is also listed on the Pacific Exchange under the same symbol.

	Low	High
2001		
1st Quarter	$ 25.00	$ 34.50
2nd Quarter	$ 23.02	$ 31.10
3rd Quarter	$ 21.90	$ 26.89
4th Quarter	$ 20.45	$ 29.23
2002		
1st Quarter	$ 23.00	$ 31.75
2nd Quarter	$ 29.44	$ 35.49
3rd Quarter	$ 25.44	$ 34.71
4th Quarter	$ 31.90	$ 39.28

As of February 26, 2003, there were 2,253 holders of record of the Company s Common Stock.

In each of 2001 and 2002, the Company paid four quarterly dividends of $0.03 per share on its Common Stock. On January 21, 2003, the Company increased its dividend 67% to $0.05 per share. The declaration and payment of future dividends, and the amount of such dividends, will depend upon, among other things, the Company s future earnings and financial condition, liquidity and capital requirements, the general economic and regulatory climate and other factors deemed relevant by the Company s Board of Directors.

The Company s revolving credit facility with its banks under which the Company has borrowed funds, and the Indentures relating to the Company s 8 3/4% Senior Subordinated Notes due 2007 (the 2007 Notes), 10 3/8% Senior Subordinated Notes due 2009 (the 2009 Notes) and 8 1/4% Senior Subordinated Notes due 2011 (the 2011 Notes) contain covenants that may restrict the ability of the Company to pay future dividends on the Company s Common Stock. The Company does not currently believe that any of these agreements will restrict the Company s ability to pay dividends on its Common Stock at any time in the reasonably foreseeable future.

20

ITEM 6. ***Selected Financial Data.***

In the following table, the Company s financial, production and other data for 2002 and 2001 reflect the Company s acquisition of North Central from and on March 14, 2001. The selected financial data should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations and the audited consolidated financial statements and notes thereto included under Financial Statements and Supplementary Data.

	For the Year Ended December 31,				
	2002	**2001(a)**	**2000(a)**	**1999(a)**	**1998(a)**
	(Expressed in thousands, except per share and production data)				
Financial Data					
Revenues:					
Crude oil and condensate	$ 431,826	$ 261,226	$ 272,932	$ 109,803	$ 74,703
Natural gas	291,975	322,390	190,401	111,152	116,148
Natural gas liquids	23,187	12,461	15,869	9,544	9,303
Oil and gas revenues	746,988	596,077	479,202	230,499	200,154
Gains (losses) on sales	3,034	1,000	3,676	37,458(c)	(92)
Other	1,419	13,040	15,113	7,159	2,741
Total	$ 751,441	$ 610,117	$ 497,991	$ 275,116	$ 202,803
Income (loss) before cumulative effect of change in accounting principle	$ 107,031	$ 87,954	$ 89,023	$ 22,134	$ (43,098)
Cumulative effect of change in accounting principle			(1,768)(b)		
Net income (loss)	$ 107,031	$ 87,954	$ 87,255	$ 22,134	$ (43,098)
Per share data:					
Income (loss) before cumulative effect of change in accounting principle -					
Basic	$ 1.85	$ 1.72	$ 2.20	$ 0.55	$ (1.14)
Diluted	$ 1.77	$ 1.62	$ 1.99	$ 0.55	$ (1.14)
Cash dividends on common stock	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12
Price range of common stock:					
High	$ 39.28	$ 34.50	$ 33.19	$ 23.44	$ 34.69
Low	$ 23.00	$ 20.45	$ 18.00	$ 8.94	$ 9.81
Weighted average number of common shares outstanding	57,963	51,031	40,445	40,178	37,902
Long-term debt at year end	$ 722,903	$ 792,561	$ 365,000	$ 375,000	$ 434,947
Minority interest at year end	$	$ 145,086	$ 144,913	$ 144,751	$
Shareholders equity at year end	$ 1,077,784	$ 824,885	$ 358,271	$ 268,512	$ 249,660
Total assets at year end	$ 2,491,593	$ 2,423,979	$ 1,114,649	$ 948,193	$ 862,396

Production (Sales) Data

Net daily average production and weighted average price:										
Natural gas (Mcf per day)		279,000		237,800		164,600		141,600		159,000
Price (per Mcf)	$	2.87	$	3.71	$	3.16	$	2.15	$	2.00
Crude oil-condensate (Bbl per day)		47,360		29,590		25,788		16,036		15,775
Price (per Bbl)	$	24.90	$	23.99	$	28.92	$	18.76	$	12.97
Natural gas liquids (Bbl per day)		4,480		2,118		2,141		2,077		2,422
Price (per Bbl)	$	14.18	$	16.12	$	20.25	$	12.59	$	10.52

(a) The Company s financial statements for 1998 2001 were audited by Arthur Andersen LLP, who have ceased operations.

(b) Crude oil and condensate from the Company s producing fields located in the Kingdom of Thailand are produced into storage vessels and are sold and recognized as revenue periodically as economic quantities are accumulated. Effective January 1, 2000, the Company adopted the provisions of the Commission s Staff Accounting Bulletin No. 101, Revenue Recognition. As a result, the Commission no longer accepts the oil and gas exploration and production industry s long-standing historical practice of recording such product inventories at their net realizable value. The cumulative effect of this change in accounting principle through December 31, 1999 ($1,768,000, net of tax benefits of $1,768,000) was charged to earnings effective January 1, 2000.

(c) Primarily reflects the gain on sale of the Company s Lopeno field in the first quarter of 1999.

	For the Year Ended December 31,				
	2002	2001	2000	1999	1998
	(Expressed in thousands)				
Capital Expenditures (including interest capitalized)					
Oil and gas:					
Domestic Offshore -					
Exploration	$ 33,600	$ 18,000	$ 18,700	$ 12,600	$ 20,200
Development	100,700	169,000	43,700	43,200	42,500
Purchase of reserves		87,700			5,000
Onshore North America -					
Exploration	14,500	38,300	19,700	9,800	16,500
Development	117,200	113,600	34,700	19,800	28,100
Purchase of reserves		1,027,200	8,400	19,500	133,100
International -					
Exploration	3,100	11,500	9,400	3,500	11,600
Development	109,300	64,700	51,500	106,300	95,500
Purchase of reserves					
Total oil and gas	378,400	1,530,000	186,100	214,700	352,500
Other	3,300	4,800	700	2,200	6,300
Total	$ 381,700	$ 1,534,800	$ 186,800	$ 216,900	$ 358,800

ITEM 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations.***

Statements in the following discussion may be forward-looking and involve risks and uncertainties. The Company s financial results are most directly affected by changing prices for its production. Changing prices can influence not only current results of operations but the determination of the Company s proved reserves and available sources of financing, including the determination of the borrowing base under its bank credit facility. The Company s results depend not only on hydrocarbon prices generally, but on its ability to market its production on favorable terms in the areas in which it is produced, including foreign areas such as Thailand where the Company s operations may be subject to local constraints on demand, currency restrictions, exchange rate fluctuations, the possibility of increases in taxes or other charges and non-renewal or other adverse action relating to concessions or contracts, and other political risks. On a longer term basis the Company s financial condition and results of operations are affected by its ability to replace reserves as they are produced through successful exploration, development and acquisition activity. The Company s results could also be adversely affected by adverse regulatory developments and operational risks associated with oil and gas operations. Some of the other risks and uncertainties that may affect the Company s results are mentioned in the discussion that follows.

On March 14, 2001, the merger of Pogo Producing Company (the Company) and NORIC Corporation (NORIC) was consummated. As a result of the merger, the Company acquired all of the outstanding capital stock of North Central Oil Corporation (North Central), an independent domestic oil and gas exploration and production company, which was the principal asset of NORIC. The merger was accounted for using the purchase method of accounting. Commencing March 14, 2001, the results of North Central s operations are consolidated with the Company s. Pursuant to the merger agreement among the Company, NORIC and certain NORIC shareholders dated as of November 19, 2000, former shareholders of NORIC received 12,615,816 shares of the Company s common stock and approximately $344,711,000 in cash. In addition, at closing the Company repaid all $78,600,000 principal amount of North Central s existing bank debt. The sources of funds used in connection with the merger included cash on hand at the Company and NORIC and borrowings under the Company s revolving credit agreement.

Pogo Trust I, a subsidiary of the Company, called its 6½% Cumulative Quarterly Income Convertible Preferred Securities due 2029 (the Trust Preferred Securities) for redemption on June 3, 2002. Prior to their redemption, holders of

2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing over $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company s common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding.

Application of Critical Accounting Policies and Management s Estimates

The discussion and analysis of the Company s financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Our significant accounting policies are described in Note 1 to our consolidated financial statements for the year ended December 31, 2002 included in this Form 10-K. We have identified below policies that are of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management. We analyze our estimates, including those related to oil and gas revenues, bad debts, oil and gas properties, marketable securities, income taxes, derivatives, contingencies and litigation, and base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of the Company s financial statements:

Successful Efforts Method Of Accounting

The Company accounts for its oil and gas exploration and development activities utilizing the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated as successful. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but such costs are charged to expense if and when the well is determined not to have found reserves in commercial quantities. In most cases, a gain or loss is recognized for sales of producing properties.

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. On occasion, wells are drilled which have targeted geologic structures that are both developmental and exploratory in nature, and in such instances an allocation of costs is required to properly account for the results. Delineation seismic costs incurred to select development locations within a productive oil and gas field are typically treated as development costs and capitalized, but often these seismic programs extend beyond the proved reserve areas and therefore management must estimate the portion of seismic costs to expense as exploratory. 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 the Company enters 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 be expensed as dry hole costs.

Reserve Estimates

The Company s estimates of oil and gas reserves are, by necessity, projections based on geologic and engineering data, and there are uncertainties inherent in the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that are difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of regulations by governmental agencies, and assumptions governing future oil and gas prices, future operating costs, severance taxes, development costs and workover costs, all of which may in fact vary considerably from actual results. The future drilling costs associated with reserves assigned to proved undeveloped locations may ultimately increase to the extent that these reserves may be later determined to be uneconomic. For these reasons, estimates of the economically recoverable quantities of expected oil and gas attributable to any particular group of properties, classifications of such reserves based on risk of recovery, and estimates of the future net cash flows may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Company s oil and gas properties and/or the rate of depletion of such oil and gas properties. Actual production, revenues and expenditures with respect to the Company s reserves will likely vary from estimates, and such variances may be material.

Impairment Of Oil and Gas Properties

The Company reviews its proved oil and gas properties for impairment on an annual basis and whenever events and circumstances indicate a potential decline in the recoverability of their carrying value. The Company estimates the expected future cash flows from its proved oil and gas properties and compares these future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to its fair value in the current period. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and a discount rate commensurate with the risk associated with realizing the expected cash flows projected. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. The Company recognized significant impairment expense due to poor reservoir performance at one of its Gulf of Mexico properties in the first quarter of 2001, and has recognized other less significant impairment expenses related to other properties in subsequent periods. Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that will require the Company to record an impairment of its oil and gas properties and there can be no assurance that such impairments will not be required in the future.

Fair Values Of Derivative Instruments

The estimated fair values of the Company s derivative instruments are recorded on the Company s consolidated balance sheet. Historically, substantially all of the Company s derivative instruments represent cash flow hedges of the price of future oil and natural gas production. Therefore, while fair values of such hedging instruments must be estimated at the end of each reporting period, the related changes in such fair values are not included in the Company s consolidated results of operations, to the extent they are expected to offset the future cash flows from oil and natural gas production. Instead, the changes in fair value of hedging instruments are recorded directly to shareholders equity until the hedged oil or natural gas quantities are produced.

The estimation of fair values for the Company s hedging derivatives requires substantial judgment. The Company estimates the fair values of its derivatives on a monthly basis using an option-pricing model. To utilize the option-pricing model, the Company uses various factors that include closing exchange prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. The estimated future prices are compared to the prices fixed by the hedge agreements, and the resulting estimated future cash inflows (outflows) over the lives of the hedges are discounted using the Company s current borrowing rates under its revolving credit facility. These pricing and discounting variables are sensitive to market volatility as well as changes in future price forecasts, regional price differentials and interest rates. Currently, all of the Company s derivative instruments are hedges of the price of crude oil and natural gas production. The Company is not involved in any derivative trading activities.

Business Combinations/Acquisitions

The Company grew substantially in 2001 through the acquisition of North Central. As stated earlier, this acquisition was accounted for using the purchase method of accounting, and subsequent accounting pronouncements require that all future acquisitions be accounted for using the purchase method.

Under the purchase method, the acquiring company adds to its balance sheet the estimated fair values of the acquired company s assets and liabilities. Any excess of the purchase price over the fair values of the tangible and intangible net assets acquired is recorded as goodwill. As of January 1, 2002, the accounting for goodwill has changed. In prior years, goodwill was amortized. Effective January 1, 2002, goodwill and other intangibles with an indefinite useful life are no longer amortized, but instead are assessed for impairment at least annually. The Company has never recorded any goodwill in connection with the acquisition of any assets. However, there can be no assurance that the Company may not do so in the future.

There are various assumptions made by the Company in determining the fair values of an acquired company s assets and liabilities. The most significant assumptions, and the ones requiring the most judgment, involve the estimated fair values of the oil and gas properties acquired. To determine the fair values of these properties, the Company prepares estimates of oil, natural gas and natural gas liquid (NGL) reserves. These estimates are based on work performed by the Company s engineers and outside petroleum reservoir consultants. The judgments associated with the estimation of reserves are described earlier in this section. The fair value of the estimated reserves acquired in a business combination is then calculated based on the Company s estimates of future oil, natural gas and NGL prices. The Company s estimates of future prices are based on its own analysis of pricing trends. These estimates are based on current data obtained with regard to regional and worldwide supply and demand dynamics, such as economic growth forecasts. They are also based on industry data regarding natural gas storage availability, drilling rig activity, changes in delivery capacity and trends in regional pricing differentials. Future price forecasts from independent third parties are also taken into account in arriving at the Company s own pricing estimates. The Company s estimates of future prices are applied to the estimated reserve quantities acquired to arrive at estimated future net revenues. For estimated proved reserves, the future net revenues are then discounted to derive a fair value for such reserves. The Company also applies these same general principles in arriving at the fair value of unproved reserves acquired in a business combination. These unproved reserves are generally classified as either probable or possible reserves. Because of their very nature, probable and possible reserve estimates are less precise than those of proved reserves. Generally, in the Company s business combinations, the determination of the fair values of oil and gas properties requires more judgment than the estimates of fair values for other acquired assets and liabilities.

Future Development and Abandonment Costs

Future development costs include costs incurred to obtain access to proved reserves, including drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, FPSOs, FSOs, gathering systems, wells and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon the type of production structure, depth of water, 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 upon numerous factors, including changing technology and the political and regulatory environment. The accounting for future development and abandonment costs changed on January 1, 2003, with the adoption of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations . See Liquidity and Capital Resources - Recent Accounting Pronouncements for a further discussion of this accounting standard.

Pension and Other Post-Retirement Benefits

Accounting for pensions and other postretirement benefits involves several assumptions including the expected rates of return on plan assets, determination of discount rates for remeasuring plan obligations, determination of inflation rates regarding compensation levels and health care cost projections. The Company develops its demographics and utilizes the work of actuaries to assist with the measurement of employee-related obligations. The assumptions used vary from year-to-year, which will affect future results of operations. Any differences among these assumptions and the results actually experienced will also impact future results of operations.

Income Taxes

For financial reporting purposes, the Company generally provides taxes at the rate applicable for the appropriate tax jurisdiction. Where the Company s present intention is to reinvest in foreign ventures the unremitted earnings of certain of its foreign operations, the Company does not provide for U.S. income taxes on such unremitted earnings of those foreign subsidiaries. Management periodically assesses the need to utilize these unremitted earnings to finance the foreign operations of the Company. 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 the Company s operations. Such estimates are inherently imprecise since many assumptions utilized in the cash flow projections are subject to revision in the future.

Management also periodically assesses, by tax jurisdiction, the probability of recovery of recorded deferred tax assets based on its assessment of future earnings outlooks. Such estimates are inherently imprecise since many assumptions utilized in the assessments are subject to revision in the future.

Results of Operations

Net Income

The Company reported net income for 2002 of $107,031,000 or $1.85 per share ($113,803,000 or $1.77 per share on a diluted basis), compared to net income for 2001 of $87,954,000 or $1.72 per share ($98,403,000 or $1.62 per share on a diluted basis), and net income for 2000 of $87,255,000 or $2.16 per share ($97,704,000 or $1.95 per share on a diluted basis). Among other items affecting net income for 2002, 2001 and 2000 were pre-tax gains of $3,034,000, $1,000,000 and $3,676,000, respectively, related to the Company s sale of certain non-strategic properties as part of its asset rationalization process. The $3,034,000 recorded in 2002 reflects gains of $3,900,000 on the sale of the Company s Sea Robin gas plant, which was partially offset by losses on the sale of various other non-strategic offshore properties. The Company has announced that it will continue to examine its non-strategic assets and will sell them if it believes that it can obtain a fair price, but that it does not currently believe that such sales will have a material impact on the Company s ongoing business activities.

Earnings per common share are based on the weighted average number of common shares outstanding for 2002 of 57,963,000 (64,321,000 on a diluted basis), compared to 51,031,000 (60,822,000 on a diluted basis) for 2001 and 40,445,000 (50,155,000 on a diluted basis) for 2000. The increase in the weighted average number of common shares outstanding for 2002, compared to 2001, resulted primarily from the conversion of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities into 6,309,972 shares of the Company s common stock on June 3, 2002 and to a much lesser extent, the issuance of shares upon the exercise of stock options pursuant to the Company s stock option plans and stock issued as compensation. The increase in the weighted average number of common shares outstanding for 2002, compared to 2000, resulted primarily from the issuance of 12,615,816 shares of common stock to former shareholders of NORIC on March 14, 2001, the conversion of the Trust Preferred Securities into the Company s common stock and to a much lesser extent, the issuance of shares upon the exercise of stock options pursuant to the Company s stock option plans and stock issued as compensation. The earnings per share computations on a diluted basis in 2002, 2001 and 2000 primarily reflect additional shares of common stock issuable upon the assumed conversion of the Company s 5½% Convertible Subordinated Notes due 2006 (the 2006 Notes) and the Trust Preferred Securities (on a weighted average basis in 2002) and the elimination of related interest requirements, as adjusted for applicable federal income taxes and, to a lesser extent, the assumed exercise of options to purchase common shares. In addition, the number of common shares outstanding in the diluted computation is adjusted to include dilutive shares that are assumed to have been issued by the Company in connection with outstanding options, less treasury shares that are assumed to have been purchased by the Company from the option proceeds.

Total Revenues

The Company s total revenues for 2002 were $751,441,000, an increase of approximately 23% compared to total revenues of $610,117,000 for 2001, and an increase of approximately 51% compared to total revenues of $497,991,000 for 2000. The increase in the Company s total revenues for 2002, compared to 2001 and 2000, resulted primarily from increased oil and gas revenues, partially offset by a decrease in pipeline sales which are included in other revenues.

Oil and Gas Revenues

The Company s oil and gas revenues for 2002 were $746,988,000, an increase of approximately 25% from oil and gas revenues of $596,077,000 for 2001, and an increase of approximately 56% from oil and gas revenues of $479,202,000 for 2000. The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in thousands) between 2002 and the previous two years:

	2002 Compared to	
	2001	**2000**
Increase (decrease) in oil and gas revenues resulting in variances in:		
Natural gas -		
Price	$ (73,521)	$ (17,653)
Production	43,106	119,227
	(30,415)	101,574
Crude oil and condensate -		
Price	9,910	(37,933)
Production	160,690	196,827
	170,600	158,894

Natural gas liquids		10,726		7,318
Increase in oil and gas revenues	$	150,911	$	267,786

The increase in the Company s oil and gas revenues in 2002, compared to 2001, is related to increases in the Company s hydrocarbon production volumes which were only partially offset by a decrease in the average price that the Company received for natural gas production volumes. The increase in the Company s oil and gas revenues in 2002, compared to 2000, is related to increases in the Company s hydrocarbon production volumes which were only partially offset by decreases in the average prices that the Company received for such production volumes. The increase in oil and gas revenues for 2002, compared to 2001 and 2000, was also partially offset by a decline in the average price that the Company received for its NGL production volumes from $20.25 and $16.12 in 2000 and 2001, respectively, to $14.18 in 2002.

Comparison of Increases (Decreases) in:	2002	2001	% Change 2002 to 2001	2000	% Change 2002 to 2000
Natural Gas --					
Average prices					
North America (a)	**$ 3.12**	$ 4.25	**(27)%**	$ 3.69	**(15)%**
Kingdom of Thailand (b)	**$ 2.22**	$ 2.30	**(3)%**	$ 2.20	**1%**
Company-wide average price	**$ 2.87**	$ 3.71	**(23)%**	$ 3.16	**(9)%**
Average daily production volumes (MMcf per day):					
North America (a)	**201.3**	172.8	**16%**	106.2	**90%**
Kingdom of Thailand	**77.8**	65.1	**20%**	58.4	**33%**
Company-wide average daily production	**279.1**	237.9	**17%**	164.6	**70%**
Crude Oil and Condensate --					
Average prices (c)					
North America	**$ 24.95**	$ 24.60	**1%**	$ 27.83	**(10)%**
Kingdom of Thailand	**$ 24.80**	$ 23.38	**6%**	$ 30.10	**(18)%**
Company-wide average price	**$ 24.90**	$ 23.99	**4%**	$ 28.92	**(14)%**
Average daily production volumes (Bbls per day):					
North America (c)	**30,971**	14,804	**109%**	13,432	**131%**
Kingdom of Thailand (d)	**16,389**	14,786	**11%**	12,356	**33%**
Company-wide average daily production	**47,360**	29,590	**60%**	25,788	**84%**
Total Liquid Hydrocarbons --					
Company-wide average daily production (Bbls per day)(d)	**51,840**	31,707	**63%**	27,929	**86%**

(a) North American average prices and production reflect production from the United States and Canada and the impact of the Company s price hedging activity**.** Price hedging activity added $0.04 and $0.23 to the average price of the Company s North American natural gas production during 2002 and 2001, respectively, and reduced the average price $0.30 during 2000. The Company sold its operations in Canada effective August 31, 2001, as part of an asset rationalization process. Consequently, results for the 2002 and a portion of the 2001 comparative periods do not reflect any production from Canada.

(b) The Company is paid for its natural gas production in the Kingdom of Thailand in Thai Baht. The average prices are presented in U.S. dollars based on the revenue recorded in the Company s financial records.

(c) North American average prices and production reflect production from the United States and Canada. The Company sold its operations in Canada effective August 31, 2001, as part of an asset rationalization process. Consequently, results for the 2002 and a portion of the 2001 comparative periods do not reflect any production from Canada. Average prices are computed on production that is actually sold during the period and include the impact of the Company s price hedging activity. Price hedging activity added $0.08 to the average price of the Company s North American crude oil and condensate production during 2002 and reduced the average price $2.03 during 2000. For North American average prices, sales volumes equate to actual production. However, in the Gulf of Thailand, crude oil and condensate sold may be more or less than actual production. See footnote (d).

(d) Oil and condensate production in the Gulf of Thailand is produced and stored on the FPSO and FSO pending sale and is sold in tanker loads that typically average between 300,000 and 750,000 barrels per sale. Therefore, oil and condensate sales volumes for a given period in the Gulf of Thailand may not equate to actual production. In accordance with generally accepted accounting principles, reported revenues are based on sales volumes. However, the Company believes that actual production volumes also provide a meaningful measure of the Company s operating results. The Company produced 58,000 barrels less than it sold in 2002, 90,000 barrels less than it sold in 2001 and 135,000 barrels more than it sold in 2000.

Natural Gas

Thailand Prices. The price that the Company receives under the Gas Sales Agreement with PTT is based upon a formula that takes into account a number of factors including, among other items, changes in the Thai/U.S. exchange rate and fuel oil prices in Singapore. The contract price is also subject to adjustments for quality. An amendment to the Gas Sales Agreement provided that for certain volumes the Company produces in excess of the base contractual amount (currently 145 MMcf per day) the price that the Company receives from PTT will be equal to 88% of the then-current price calculated under its Gas Sales Agreement. The decrease in the average price that the Company received for its natural gas production in the Kingdom of Thailand for 2002 compared to 2001 and 2000, reflects a downward adjustment in the average price received under the Gas Sales Agreement and, to a lesser extent, a reduced average price received on the excess production sold at lower prices. See Business International Operations; Contractual Terms Governing the Thailand Concession and Related Production.

Production. The increase in the Company s natural gas production during 2002, compared to 2001 and 2000, was primarily related to production from properties acquired in the North Central acquisition, successful development programs on the Company s Gulf of Mexico properties, including its Mississippi Canyon Blocks 661/705 Field, and increased Thailand production, partially offset by natural production declines at other properties and weather related shut downs in the Gulf of Mexico.

Crude Oil and Condensate

Thailand Prices. Since the inception of production from the Tantawan Field, crude oil and condensate have been stored on the FPSO until an economic quantity is accumulated for offloading and sale. The first such sale of crude oil and condensate from the Tantawan Field occurred in July 1997. Commencing in July 1999 when production began from the Benchamas Field, crude oil and condensate from that field has been stored on the FSO and sold as economic quantities were accumulated. A typical sale ranges from 300,000 to 750,000 barrels. Prices that the Company receives for its crude oil and condensate production from Thailand are based on world benchmark prices, typically as a differential to Malaysian Tapis crude, and are denominated in U.S. dollars. As discussed further under Costs and Expenses, Lease Operating Expenses, the Company records all crude oil held in the FPSO and the FSO at the end of an accounting period as inventory held at cost. When such crude oil is sold, usually during the following month, the difference between the cost of the crude oil and the sales revenue is recognized in the income statement.

Production. The increase in the Company s crude oil and condensate production during 2002, compared to 2001 and 2000, resulted primarily from the continuing success of the Company s development program in the Benchamas Field in the Kingdom of Thailand, the commencement of production from the Company s Main Pass Blocks 61/62 Field, its Mississippi Canyon 661/705 Field and its Ewing Bank Block 871 Field and, to a lesser extent, increased crude oil and condensate production in the Kingdom of Thailand. These increases were partially offset by natural production declines at certain other properties and weather-related shut downs in the Gulf of Mexico.

In accordance with generally accepted accounting principles, the Company records its oil production in the Kingdom of Thailand at the time of sale, rather than when produced. At the end of each quarter, the crude oil and condensate stored on board the FSO and FPSO pending sale is accounted for as inventory at cost. Reported revenues are based on sales volumes. When a tanker load of oil is sold in Thailand, the entire amount will be accounted for as production sold, regardless of when it was produced. As of December 31, 2002, the Company had approximately 202,000 net barrels stored on board the FPSO and FSO.

NGL Production. The Company s oil and gas revenues, and its total liquid hydrocarbon production, reflect the production and sale by the Company of NGL, which are liquid products that are extracted from natural gas production. The increase in NGL revenues for 2002, compared with 2001 and 2000, primarily related to NGL removed from the Company s Mississippi Canyon Blocks 661/705 Field gas production. These increases were partially offset by a decline in the average prices that the Company received for its NGL production during the comparative periods, from $20.25 in 2000 to $16.12 in 2001 and $14.18 in 2002.

Costs and Expenses

Comparison of Increases (Decreases) in:		2002		2001	% Change 2002 to 2001		2000	% Change 2002 to 2000
Lease Operating Expenses								
North America	$	101,201,000	$	81,164,000	25%	$	60,072,000	68%
Kingdom of Thailand	$	38,247,000	$	36,993,000	3%	$	33,568,000	14%
Total Lease Operating Expenses	$	139,448,000	$	118,157,000	18%	$	93,640,000	49%
General and Administrative Expenses	$	49,490,000	$	39,162,000	26%	$	34,568,000	43%
Exploration Expenses	$	4,783,000	$	23,373,000	(80%)	$	15,291,000	(69)%
Dry Hole and Impairment Expenses	$	26,999,000	$	26,945,000	0%	$	28,608,000	(6)%
Depreciation, Depletion and Amortization (DD&A) Expenses	$	287,809,000	$	206,609,000	39%	$	131,151,000	119%
DD&A rate	$	1.33	$	1.32	1%	$	1.07	25%
Mcfe sold (a)		215,728,000		156,780,000	38%		121,581,000	77%
Natural Gas Purchases and Other	$	2,739,000	$	15,990,000	(83)%	$	15,090,000	(82)%
Interest								
Charges	$	(57,450,000)	$	(56,259,000)	2%	$	(34,064,000)	69%
Interest Income	$	1,760,000	$	3,226,000	(45)%	$	2,634,000	(33)%
Capitalized Interest Expense	$	24,033,000	$	33,242,000	(28)%	$	20,918,000	15%
Minority Interest - Dividends and Costs	$	(4,140,000)	$	(9,999,000)	(59)%	$	(9,965,000)	(58)%
Foreign Currency Transaction Gain (Loss)	$	435,000	$	(524,000)	(183)%	$	(3,174,000)	(114)%
Income Tax Expense	$	(97,780,000)	$	(61,613,000)	59%	$	(66,969,000)	46%

(a) Mcfe stands for thousands of cubic feet equivalent

Lease Operating Expenses

The increase in North American lease operating expenses for 2002, compared to 2001, is related to higher production from the Company s Gulf of Mexico properties, and to a lesser extent, increased maintenance costs during 2002, partially offset by decreased severance taxes. As a result of the increased production from its Gulf of Mexico properties, the Company has also incurred increased product transportation and processing expenses and increased rental expenses for compressors and other equipment during 2002. In addition to the above factors, the increased lease operating expenses associated with properties acquired in the acquisition of North Central (completed on March 14, 2001) also impact the comparison of 2002 to 2001. The increase in North American lease operating expenses for 2002, compared to 2000, was primarily related to increased costs in 2002 associated with properties acquired in the North Central acquisition, higher production from the Company s Gulf of Mexico properties, increased product transportation and processing expenses and increased rental expenses for compressors and other equipment related to the higher production levels.

The increase in lease operating expenses in the Kingdom of Thailand for 2002, compared to 2001, primarily related to an increase in insurance expenses related to the construction of platforms and processing facilities for the Benchamas Field. The increase in lease operating expenses in the Kingdom of Thailand for 2002, compared to 2000, primarily related to increased equipment rental expenses and increased insurance expenses related to construction of platforms for the Benchamas Field. In accordance with generally accepted accounting principles, the portion of lifting costs that is attributable to crude oil and condensate stored on the FPSO and FSO is treated as an inventoried cost until that crude oil and condensate is sold. At the time the crude oil and condensate is sold, those inventoried lifting costs are recognized as lease operating expenses. Variances in production, sales and operating costs will result in variances in the amount of lease operating expense that is currently recognized as expense and the amount recorded as product inventory to be recognized in subsequent periods. A substantial portion of the Company s lease operating expenses in the Kingdom of Thailand relates to the lease payments made in connection with the bareboat charter of the FPSO for the Tantawan Field and the FSO for the Benchamas Field. Collectively, these lease payments accounted for approximately $14,500,000, $14,500,000 and $15,100,000 (net to the Company s interest) of the Company s Thailand lease operating expenses for 2002, 2001 and 2000, respectively. The Company currently expects these lease payments to remain relatively constant at approximately $14,500,000 (net to the Company s interest) for the next four years. See Liquidity and Capital Resources; Capital Requirements; Other Material Long-Term Commitments.

On a per unit of production basis, the Company s total lease operating expenses have continued to decrease slightly from an average of $0.77 per Mcfe for 2000 and $0.75 per Mcfe for 2001 to $0.65 per Mcfe for 2002.

General and Administrative Expenses

The increase in general and administrative expenses for 2002, compared with 2001 and 2000, primarily related to increased expenses associated with the Company s acquisition of North Central and its employees, as well as other increases in the size of the Company s work force, normal increases in compensation and concomitant benefit expense and, to a lesser extent, increases in map purchases, office rent, insurance costs and audit fees. On a per unit of production basis, the Company s general and administrative expenses declined to $0.23 per Mcfe in 2002, from $0.25 per Mcfe in 2001 and $0.28 per Mcfe in 2000.

Exploration Expenses

Exploration expenses consist primarily of rental payments required under oil and gas leases to hold non-producing properties (delay rentals) and exploratory geological and geophysical costs that are expensed as incurred. The decrease in exploration expenses for 2002, compared to 2001 and 2000, resulted primarily from a decrease in 3-D seismic acquisition activities during 2002. The 2001 and 2000 expense includes the cost of conducting 3-D surveys in Hungary, the cost of acquiring substantial new speculative 3-D data sets in the Gulf of Mexico and seismic operations in Canada. The 2001 expense also includes the cost of transferring certain seismic licenses in connection with the North Central acquisition. There were no comparable expenses incurred in 2002.

Dry Hole and Impairment Expenses

Dry hole and impairment expenses relate to costs of unsuccessful exploratory wells drilled and impairment of oil and gas properties. During 2002 the Company drilled 6 gross unsuccessful exploratory wells (5.17 net to the Company s interest), in 2001 the Company drilled 6 gross unsuccessful exploratory wells (3.06 net to the Company s interest) and in 2000 the Company drilled 13 gross unsuccessful exploratory wells (6.22 net to the Company s interest.) Inclusive of development drilling, the Company had an overall drilling success rate of 92% in 2002, 93% in 2001 and 87% in 2000. Generally accepted accounting principles also require that if the expected future cash flow of the Company s reserves on a property fall below the cost that is recorded on the Company s books, these reserves must be impaired and written down to the property s fair value. Depending on market conditions, including the prices for oil and natural gas, and the results of operations, a similar test may be conducted at any time to determine whether impairments are appropriate. Depending on the results of this test, an impairment could be required on some of the Company s properties and this impairment could have a material negative non-cash impact on the Company s earnings and balance sheet.

Depreciation, Depletion and Amortization Expenses

The Company s provision for DD&A expense is based on its capitalized costs, plus future costs to abandon offshore wells and platforms, and is determined on a cost center by cost center basis using the units of production method. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico and Gulf of Thailand. Generally, the Company establishes cost centers on the basis of an oil or gas trend or play for its onshore oil and gas activities. The increase in the Company s DD&A expenses for 2002, compared to 2001 and 2000, resulted primarily from an increase in the Company s natural gas and liquid hydrocarbon production and, to a lesser extent, an increase in the Company s composite DD&A rate.

The increase in the composite DD&A rate for all of the Company s producing fields for 2002, compared to 2001 and 2000, resulted primarily from having a full year s production from fields acquired in the North Central acquisition that, because they were valued at fair market value in connection with the acquisition, contribute a DD&A rate higher than the Company s historic average. The increase was partially offset by an increased percentage of the Company s production coming from certain of the Company s fields that have DD&A rates that are lower than the Company s recent historical composite rate (principally the Benchamas Field and certain Gulf of Mexico properties) and a corresponding decrease in the percentage of the Company s production coming from fields that have DD&A rates that are higher than the Company s recent historical composite DD&A rate.

Natural Gas Purchases and Other

Revenue from the sale of natural gas purchased for resale is reported under Revenues - Other. The cost of purchasing natural gas, in addition to the costs of operating the Company s pipeline carrying the natural gas, is recorded as an expense under Natural gas purchases and other. During 2001 and 2000, primarily all of the natural gas purchased and resold by the Company was transported on Pogo Onshore Pipeline Company s Saginaw pipeline, which was sold during the fourth quarter of 2001 as part of the Company s ongoing asset rationalization process. During 2002, substantially all of the gas purchased by the Company is the result of purchases of natural gas volumes required to replace the reduction in heating content of the gas stream after the extraction of NGLs. These purchases were made to bring the gas stream to pipeline quality standards. Prior to 2002, the Company had been using its own natural gas production to replenish this extracted gas. Consequently, there is no meaningful comparison between the 2002 period and the 2001 and 2000 periods.

Interest

Interest Charges. The increase in the Company s interest charges for 2002, compared to 2001 and 2000, resulted primarily from an increase in the average amount of the Company s outstanding debt (largely related to the acquisition of North Central in March 2001), partially offset by a decline in the average interest rate on the outstanding debt.

Interest Income. The decrease in the Company s interest income for 2002, compared to 2001 and 2000, resulted primarily from a decrease in the interest rate received, partially offset by an increase in the amount of cash and cash equivalents temporarily invested. The cash and cash equivalents on the Company s balance sheet are primarily held by the Company s international subsidiaries for future investment overseas, in part due to the negative tax effects that would result from the repatriation of these funds.

Capitalized Interest. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are substantially complete and ready for their intended use if projects are evaluated as successful. The change in capitalized interest for 2002, compared to 2001 and 2000, resulted primarily from a decrease in the amount of capital expenditures subject to interest capitalization during 2002 (approximately $346,000,000), compared to 2001 (approximately $365,000,000), and an increase in the amount of capital expenditures subject to interest capitalization during 2002 compared to 2000 (approximately $248,000,000). These changes were also impacted by a decrease in the computed rate incurred by the Company and applied to such capital expenditures to arrive at the total amount of capitalized interest. A substantial percentage of the Company s capitalized interest related to unevaluated properties acquired in the North Central acquisition and capital expenditures for the development of the Benchamas Field in the Gulf of Thailand, as well as several development projects in the Gulf of Mexico.

Minority Interest Dividends and Costs Associated with Mandatorily Redeemable Convertible Preferred Securities of a Subsidiary Trust

Pogo Trust I, a business trust in which the Company owned all of the issued common securities, issued $150,000,000 of Trust Preferred Securities on June 2, 1999. Pogo Trust I called the Trust Preferred Securities for redemption on June 3, 2002. Prior to their redemption, holders of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing over $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company s common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding. The amounts recorded under Minority Interest Dividends and Costs Associated with Preferred Securities of a Subsidiary Trust principally reflect cumulative dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities.

Foreign Currency Transaction Gain (Loss)

The foreign currency transaction gain reported in 2002 and the losses reported for 2001 and 2000 resulted primarily from the fluctuation against the U.S. dollar of cash and other monetary assets and liabilities denominated in Thai Baht related to the Company s Thai operations. During 2002, the Thai Baht U.S. dollar daily average exchange rate fluctuated between 40.4 and 44.4 Baht to the U.S. dollar. The Company cannot predict what the Thai Baht to U.S. dollar exchange rate will be in the future. As of February 26, 2003, the Company was not a party to any financial instrument that was intended to constitute a foreign currency hedging arrangement.

Income Tax Expense

Changes in the Company s income tax expense are a function of the Company s consolidated effective tax rate and its pre-tax income. The increase in the Company s tax expense for 2002, compared to 2001 and 2000, resulted primarily from an increase in the Company s effective tax rate during the comparative periods and from increased pre-tax income during 2002. The Company s consolidated effective tax rate for 2002, 2001 and 2000 was 48%, 41% and 43%, respectively. The higher effective tax rate is the result of higher pre-tax income derived from the Company s Thailand operations during the comparative periods, which is taxed at a rate higher than the U.S. statutory rate, relative to its pre-tax income from North American operations. Management currently expects that foreign income taxes will constitute a substantial portion of its overall tax burden for the foreseeable future.

Liquidity and Capital Resources

The Company s cash flow provided by operating activities for 2002 was $466,479,000. This compares to cash flow from operating activities of $368,076,000 in 2001 and $239,059,000 in 2000. The resulting increases are attributable to the reasons described under Results of Operations above. Cash flow from operating activities in 2002 was more than adequate to fund $368,466,000 in cash expenditures for capital and exploration projects for the year. The Company also repaid approximately $70,000,000 of financing obligations during 2002. As of December 31, 2002, the Company had cash and cash equivalents of $134,449,000 (including $118,987,000 in international subsidiaries which the Company currently intends to reinvest in its foreign operations), positive working capital, excluding cash, of $3,522,000 and long-term debt obligations of $724,987,000 (excluding debt discount of $2,084,000) with no repayment obligations until 2006. In addition, the Company had $365,000,000 of available borrowing capacity under its revolving credit facility. See Capital Structure Credit Facility .

Future Capital and Other Expenditure Requirements

The Company s capital and exploration budget for 2003, which does not include any amounts that may be expended for the purchase of proved reserves or any interest which may be capitalized resulting from projects in progress, was established by the Company s Board of Directors at $320,000,000. The Company currently anticipates that its cash provided by operating activities, available cash and cash investments and funds available under its Credit Agreement and its banker s acceptance facility, will be sufficient to fund the Company s ongoing operating, interest and general and administrative expenses, its authorized capital budget and dividend payments at current levels for the forseeable future. The declaration and amount of future dividends on the Company s common stock will depend upon, among other things, the Company s future earnings and financial condition, liquidity and capital requirements, its ability to pay dividends and other payments under certain covenants contained in its debt instruments, the general economic and regulatory climate and other factors deemed relevant by the Company s Board of Directors.

Other Material Long-Term Commitments

Contractual Cash Obligations. The Company s material contractual cash obligations include long-term debt, operating leases, and other contracts. 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 and other factors. See Quantitative and Qualitative Disclosure about Market Risk.

A summary of the Company s known contractual cash obligations as of December 31, 2002 are set forth on the following table**:**

	Payments Due By Year (in millions)						
	2003	**2004**	**2005**	**2006**	**2007**	**After 2007**	**Total**
Long Term Debt	$ 0.0	$ 0.0	$ 0.0	$ 275.0	$ 100.0	$ 350.0	$ 725.0
Operating Leases (a)	$ 21.7	$ 21.5	$ 21.4	$ 21.3	$ 18.1	$ 46.7	$ 150.7
Drilling obligations (b)	$ 9.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 9.0
Firm transportation agreements (c)	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 3.9	$ 9.9
Total	$ 31.9	$ 22.7	$ 22.6	$ 297.5	$ 119.3	$ 400.6	$ 894.6

(a) Operating leases principally include the lease of the FPSO and FSO in Thailand, the Company s office lease commitments and various other equipment rentals, including gas compressors. Where rented equipment, such as compressors, is considered essential to the operation of the oil and gas property, the Company has assumed that such equipment will be leased for the estimated productive life of the reserves, even if the existing contract for such equipment terminates prior to such date.

(b) This represents the Company s share of the contractual commitments for one rig drilling in the Gulf of Thailand and its license commitment to drill a well in the Danish North Sea. No other drilling rigs working for the Company are currently under contracts that have a term greater than six months or cannot be terminated at the end of the well that is currently being drilled. Due to their short-term nature and our inability to quantify the remaining liabilities on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(c) Firm transportation agreements represent ship-or-pay arrangements whereby the Company has committed to ship certain volumes of gas for a fixed transportation fee (principally from the Madden Field in Wyoming). The Company entered into these arrangements to ensure its access to gas markets and currently expects to produce sufficient volumes to satisfy substantially all of its firm transportation obligations.

Commitments under Joint Operating Agreements. The oil and gas industry operates in many instances through joint ventures under joint operating agreements and the Company s operations are no exception. Typically, the operator under a joint operating agreement enters into contracts, such as drilling contracts, for the benefit of all joint venture partners. Through the joint operating agreement, the non-operators reimburse, and in some cases advance, the funds necessary to meet the contractual obligations entered into by the operator. These obligations are typically shared on a working interest basis. The joint operating agreement provides remedies to the operator in the event that the non-operator does not satisfy its share of the contractual obligations. Occasionally, the operator is permitted by the joint operating agreement to enter into lease obligations and other contractual commitments that are then passed on to the non-operating joint interest owners as lease operating expenses, frequently without any identification as to the long-term nature of any commitments underlying such expenses. The contractual obligations set forth above represent the Company s working interest share of the contractual commitments that it has entered into as operator and, to the extent that it is aware, the contractual commitments entered into by the operator of projects that the Company does not operate.

Surety Bonds. In the ordinary course of the Company s business and operations, it is required to post surety bonds from time to time with third parties, including governmental agencies, primarily to cover self insurance, site restoration, equipment dismantlement, plugging and abandonment obligations. As of December 31, 2002, the Company had obtained surety bonds from a number of insurance and bonding institutions covering certain operations in the United States in the aggregate amount of approximately $7,000,000 that are not included in the prior table. In connection with their administration of offshore leases in the Gulf of Mexico, the MMS annually evaluates each lessee s plugging and abandonment liabilities. The MMS reviews this information and applies certain financial tests including, but not limited to, current asset and net worth tests. The MMS determines whether each lessee is financially capable of paying the estimated costs of such plugging and abandonment liabilities. The Company must annually provide the MMS with financial information. If the Company does not satisfy the MMS requirements, it could be required to post supplemental bonds. In the past, the Company has not been required to post supplemental bonds; however, there can be no assurance that the Company will satisfy the financial tests and remain on the list of MMS lessees exempt from the supplemental bonding requirements. The Company cannot predict or quantify the amount of any such supplemental bonds or the annual premiums related thereto and therefore has not included them in the prior table, but the amount could be substantial.

Guarantee and Letters of Credit. The Company has also issued performance guarantees related to the operations of its subsidiaries in Thailand, Hungary, the United Kingdom and Denmark. If its subsidiaries do not fulfill their contractual obligations or legal obligations under the relevant local laws, the Company could be obligated to make payments to satisfy the subsidiaries obligations. Most of these obligations relate to work commitments, plugging, abandoment, site restoration and compliance with environmental laws. The Company also has guaranteed performance of its subsidiaries obligations under the FPSO lease. To the extent quantifiable, such subsidiaries contractual commitments have been included in the prior table. However, the Company s guarantee of these obligations has not been so included. Currently, a letter of credit in the amount of $1.4 million has been issued on the Company s behalf.

Capital Structure

Credit Facility. Effective March 8, 2001, the Company entered into a revolving credit facility (the Credit Facility) with a group of lenders. The Credit Facility provides for a $515,000,000 revolving loan facility terminating on March 7, 2006. The amount that may be borrowed under the new facility may not exceed a borrowing base that is determined no less than semi-annually and is calculated based upon substantially all of the Company s proved oil and gas properties. The borrowing base is currently set at $500,000,000. The next redetermination of the borrowing base is expected to occur by May 1, 2003. The borrowing base is determined by the lenders based on their own proprietary credit criteria, which appear to be strongly correlated to the quantity of the Company s proven oil and gas reserves and the lenders expectations as to the future revenues that the Company can expect to receive from the sale of these oil and gas reserves. A significant decline in the prices that the Company is expected to receive for its future oil and gas production could have a materially negative impact on the borrowing base under the Credit Facility which, in turn, could have a material negative impact on the Company s liquidity. The Credit Facility is governed by various financial and other covenants, including requirements to maintain positive working capital (excluding current maturities of debt) and a fixed charge coverage ratio, and limitations on creation of liens, commodity hedging above specified limits, the prepayment of subordinated debt, the payment of dividends, mergers and consolidations, investments and asset dispositions. In addition, the Company is prohibited from pledging borrowing base properties as security for other debt. The Company has pledged the stock of North Central and its inter-company receivables with North Central as collateral for its obligations under the Credit Facility. If at a redetermination of the borrowing base, the lenders reduce the borrowing base below the amount then outstanding under the Credit Agreement and other senior debt arrangements, the Company must repay the excess to the lenders in no more than five substantially equal monthly installments, commencing not later than 90 days after the Company is notified of the new borrowing base. The Credit Facility also permits short-term swing line loans and the issuance of up to $50,000,000 in letters of credit as a part of the facility. Borrowings under the Credit Facility bear interest, at the Company s option, at a base (prime) rate plus a variable margin (currently none) or LIBOR plus a variable margin (currently 1.125%). The margin varies as a function of the percentage of the borrowing base being utilized and, with respect to the LIBOR rate loans, the Company s credit rating. A commitment fee on the unborrowed amount that is currently available under the Credit Facility is also charged based upon the percentage of the borrowing base that is being utilized. As of February 26, 2003, there was $105,000,000 outstanding under the Credit Facility.

Banker s Acceptances. Under a Master Banker s Acceptance Agreement, one of the Company s lenders makes available to the Company banker s drafts on an uncommitted basis up to $25,000,000. Drafts drawn under this agreement are reflected as long-term debt on the Company s balance sheet because the Company currently has the ability and intent to reborrow such amounts under the Credit Facility. The Company s 2011 Notes, 2009 Notes and its 2007 Notes may restrict all or a portion of the amounts that may be borrowed under the Master Banker s Acceptance Agreement as senior debt. The Master Banker s Acceptance Agreement permits either party to terminate the letter agreement at any time upon five-business days notice. As of February 26, 2003, there was $24,957,000 outstanding under this agreement.

2011 Notes. On April 10, 2001, the Company issued $200,000,000 principal amount of 2011 Notes. The 2011 Notes bear interest at a rate of 8¼%, payable semi-annually in arrears on April 15 and October 15 of each year. The 2011 Notes are general unsecured senior subordinated obligations of the Company, are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the Credit Facility and its Banker s Acceptances, are equal in right of payment to the 2009 Notes and the 2007 Notes, but are senior in right of payment to the Company s subordinated indebtedness, which currently includes the 2006 Notes. The Company, at its option, may redeem the 2011 Notes in whole or in part, at any time on or after April 15, 2006, at a redemption price of 104.125% of their principal value and decreasing percentages thereafter. The indenture governing the 2011 Notes also imposes certain covenants on the Company that are substantially identical to the covenants contained in the indentures governing the 2009 Notes and the 2007 Notes, including covenants limiting: incurrence of indebtedness including senior indebtedness; restricted payments; the issuance and sales of restricted subsidiary capital stock; transactions with affiliates; liens; disposition of proceeds of asset sales; non-guarantor restricted subsidiaries; dividends and other payment restrictions affecting restricted subsidiaries; and mergers, consolidations and the sale of assets.

2009 Notes. On January 15, 1999, the Company issued $150,000,000 principal amount of 2009 Notes. The 2009 Notes bear interest at a rate of 10 3/8 %, payable semi-annually in arrears on February 15 and August 15 of each year. The 2009 Notes are general unsecured senior subordinated obligations of the Company, are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the Credit Facility and its Banker s Acceptances, are equal in right of payment to the 2007 Notes and 2011 Notes, but are senior in right of payment to the Company s subordinated indebtedness, which currently includes the 2006 Notes. The Company, at its option, may redeem the 2009 Notes in whole or in part, at any time on or after February 15, 2004, at a redemption price of 105.188% of their principal value and decreasing percentages thereafter. The indenture governing the 2009 Notes also imposes certain covenants on the Company that are substantially identical to the covenants contained in the indenture governing the 2011 Notes described previously and the 2007 Notes.

2007 Notes. On May 22, 1997, the Company issued $100,000,000 principal amount of 2007 Notes. The 2007 Notes bear interest at a rate of 8 ¾ %, payable semi-annually in arrears on May 15 and November 15 of each year. The 2007 Notes are general unsecured senior subordinated obligations of the Company, are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the Credit Facility and its Banker s Acceptances, are equal in right of payment to the 2009 Notes and 2011 Notes, but are senior in right of payment to the Company s subordinated indebtedness, which currently includes the 2006 Notes. The 2007 Notes are currently redeemable at the option of the Company, in whole or in part, at any time, at a redemption price of 104.375% of their principal. The redemption premium will decline to 102.917% on May 15, 2003 and will continue to decrease over the next several years. The indenture governing the 2007 Notes also imposes certain covenants on the Company that are substantially identical to the covenants contained in the indenture governing the 2011 Notes described previously and the 2009 Notes.

2006 Notes. The outstanding principal amount of 2006 Notes was $115,000,000 as of December 31, 2002. The 2006 Notes are convertible into Common Stock at $42.185 per share, subject to adjustment upon the occurrence of certain events. The 2006 Notes bear interest at a rate of 5 ½ %, payable semi-annually in arrears on June 15 and December 15 of each year. The 2006 Notes are general unsecured subordinated obligations of the Company, are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the Credit Facility, its Banker s Acceptances and its senior subordinated indebtedness, which currently includes the 2011 Notes, 2009 Notes and the 2007 Notes. The 2006 Notes are currently redeemable at the option of the Company, in whole or in part, at any time, at a redemption price of 102.2% of their principal. The redemption premium will decline over the next several years.

Other Matters

Inflation. Publicly held companies are asked to comment on the effects of inflation on their business. Currently annual inflation in terms of the decrease in the general purchasing power of the dollar is running much below the general annual inflation rates experienced in the past. While the Company, like other companies, continues to be affected by fluctuations in the purchasing power of the dollar due to inflation, such effect is not currently considered significant.

Southeast Asia Economic Issues. A substantial portion of the Company s oil and gas operations are conducted in Southeast Asia, and a substantial portion of its natural gas and liquid hydrocarbon production is sold there. Southeast Asia in general, and the Kingdom of Thailand in particular, experienced severe economic difficulties in 1997 and 1998 which were characterized by sharply reduced economic activity, illiquidity, highly volatile foreign currency exchange rates and unstable stock markets. Since that time, the economic situation in the Kingdom of Thailand has generally stabilized. However, as with most emerging market economies, the Thai economy remains particularly sensitive to worldwide economic trends. The economic health of the Thai economy and its effect on the volatility of the Thai Baht against the dollar will continue to have a material impact on the Company s operations in the Kingdom of Thailand, together with the prices that the Company receives for its oil and natural gas production there. See Results of Operations; Oil and Gas Revenues and Results of Operations; Foreign Currency Transaction Gain (Loss).

All of the Company s current natural gas production from the Thailand Concession is committed under a long-term Gas Sales Agreement to PTT at prices denominated in Thai Baht which are determined in accordance with a formula that is intended to ameliorate, at least in part, any decline in the purchasing power of the Thai Baht against the dollar. See Business International Operations; Contractual Terms Governing the Thailand Concession and Business Miscellaneous; Sales. Although the Company currently believes that PTT will honor its commitments under the Gas Sales Agreement, a failure by PTT to honor such commitments could have a material adverse effect on the Company. During 2001, the government of Thailand partially privatized the Petroleum Authority of Thailand, forming PTT and retaining an ownership interest of approximately 70%. PTT is a publicly traded entity that currently constitutes one of, if not the largest, public companies in the Kingdom of Thailand. However, its contractual obligations are no longer backed by the full faith and credit of the Thai government.

Prices that the Company receives for production from its Thailand Concession are based on world benchmark prices, which are denominated in dollars, and are typically paid in dollars. See Business International Operations; Contractual Terms Governing the Thailand Concession and Related Production and Business Miscellaneous; Sales.

Recent Accounting Pronouncements

The Financial Accounting Standards Board (FASB) has issued several new pronouncements including, Statement of Financial Accounting Standards No. 143 (SFAS 143), Accounting for Asset Retirement Obligations , Statement of Financial Accounting Standards No. 146, Accounting for Exit or Disposal Activities (SFAS 146) and Statement of Financial Accounting Standards No. 148, Accounting for Stock Based Compensation Transition and Disclosure an amendment of FAS No. 123 (SFAS 148 .)

SFAS 143. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The Company adopted this standard as required on January 1, 2003 and will reflect an after-tax non-cash charge to earnings of approximately $4 million representing the cumulative effect of the change in accounting principle.

SFAS 146. SFAS 146 addresses significant issues regarding the recognition, measurement and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance set forth in EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity . The Company adopted this standard as required on January 1, 2003. Implementation of the new standard had no impact upon adoption and is not expected to have a material financial statement impact on the Company.

SFAS 148. SFAS 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for employee stock-based compensation. In addition, SFAS 148 requires prominent disclosures in both annual and interim financial statements about the method of accounting for employee stock-based compensation and the effect of the method used on reported results. Effective January 1, 2003, the Company adopted the fair value recognition provisions of SFAS 123, prospectively to all employee awards granted, modified or settled after January 1, 2003. The adoption of the fair value recognition provisions of SFAS 123 will result in compensation expense for stock option grants. Had the Company followed the fair value recognition provisions of SFAS 123 during 2002, net income and shareholders equity would have been reduced by approximately $5.7 million. However, since the Company has elected a prospective transition method, the impact on 2003 net income will be limited to awards granted after January 1, 2003, and no compensation expense will be recognized on unvested awards outstanding at January 1, 2003.

ITEM 7A. ***Quantitative and Qualitative Disclosures About Market Risk.***

The Company is exposed to market risk, including adverse changes in commodity prices, interest rates and foreign currency exchange rates as discussed below.

Commodity Price Risk

The Company produces, purchases and sells natural gas, crude oil, condensate and NGLs. As a result, the Company s financial results can be significantly affected as these commodity prices fluctuate widely in response to changing market forces. In the past, the Company has made limited use of a variety of derivative financial instruments only for non-trading purposes as a hedging strategy to manage commodity prices associated with oil and gas sales and to reduce the impact of commodity price fluctuations. See Business Competition and Market Conditions.

Interest Rate Risk

From time to time, the Company has entered into various financial instruments, such as interest rate swaps, to manage the impact of changes in interest rates. As of February 26, 2003, the Company has no open interest rate swap or interest rate lock agreements. Therefore, the Company s exposure to changes in interest rates primarily results from its short-term and long-term debt with both fixed and floating interest rates. The following table presents principal or notional amounts (stated in thousands) and related average interest rates by year of maturity for the Company s debt obligations and their indicated fair market value at December 31, 2002:

	2002	2003	2004	2005	2006	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 0	$ 160,000	$ 0	$ 160,000	$ 160,000
Average Interest Rate					2.52%		2.52%	
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 115,000	$ 450,000	$ 565,000	$ 598,961
Average Interest Rate					5.50%	9.07%	8.34%	

Foreign Currency Exchange Rate Risk

In addition to the U.S. dollar, the Company and certain of its subsidiaries conduct their business in Thai Baht and Hungarian Forint and are therefore subject to foreign currency exchange rate risk on cash flows related to sales, expenses, financing and investing transactions. The Company conducts a substantial portion of its oil and gas production and sales in Southeast Asia. Southeast Asia in general, and the Kingdom of Thailand in particular, have experienced severe economic difficulties in the recent past, including sharply reduced economic activity, illiquidity, highly volatile foreign currency exchange rates and unstable stock markets. See Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations; Foreign Currency Transaction Gain (Loss) and Liquidity and Capital Resources; Other Matters; Southeast Asia Economic Issues. The economic situation in Thailand and the volatility of the Thai Baht against the dollar could have a material impact on the Company s Thailand operations and prices that the Company receives for its oil and gas production there. Although the Company s sales to PTT under the Gas Sales Agreement are denominated in Baht, because predominantly all of the Company s crude oil sales and its capital and most other expenditures in the Kingdom of Thailand are denominated in dollars, the dollar is the functional currency for the Company s operations in the Kingdom of Thailand. As of February 26, 2003, the Company is not a party to any foreign currency exchange agreement.

Exposure from market rate fluctuations related to activities in Hungary, where the Company s functional currency is the legal tender in Hungary (currently the Forint), is not material at this time.

Current Hedging Activity

As of December 31, 2002, the Company held various derivative instruments. During 2002, the Company entered into natural gas and crude oil option agreements referred to as collars . Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to credit worthiness of its counterparties.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these transactions is based upon various factors that include closing exchange prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. Further details related to the Company s hedging activities as of December 31, 2002, are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling	Fair Value of Liability
Natural Gas Contracts (MMBtu) (a)				
Collar Contracts:				
January 2003 - December 2003	14,600	$ 3.85	$ 5.00	$ (2,127,192)
Crude Oil Contracts (Barrels)				
Collar Contracts:				
January 2003 - December 2003	3,650,000	$ 25.00	$ 30.00	$ (305,636)

(a) MMBtu means million British Thermal Units.

In January 2003, the Company entered into additional natural gas collars to establish floor and ceiling prices on anticipated future natural gas production. The Company has designated these contracts as cash flow hedges. Further details related to this hedging activity is as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	NYMEX Contract Price Ceiling
Natural Gas Contracts (MMBtu)			
Collar Contracts:			
February 2003 - December 2003	6,680	$ 4.25	$ 7.00

ITEM 8. ***Financial Statements and Supplementary Data.***

REPORT OF INDEPENDENT ACCOUNTANTS

To the Shareholders and Board of

Directors of Pogo Producing Company:

In our opinion, the accompanying consolidated balance sheet as of December 31, 2002 and the related consolidated statements of income, shareholders equity and cash flows present fairly, in all material respects, the financial position of Pogo Producing Company (the Company) and its subsidiaries at December 31, 2002, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. 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 audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion. The financial statements of the Company as of December 31, 2001, and for each of the two years in the period ended December 31, 2001, were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on those financial statements in their report dated February 28, 2002.

PRICEWATERHOUSECOOPERS LLP

Houston, Texas

February 21, 2003

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

THE FOLLOWING REPORT IS A COPY OF THE PREVIOUSLY ISSUED REPORT FROM ARTHUR ANDERSEN LLP (ANDERSEN). ANDERSEN DID NOT PERFORM ANY PROCEDURES IN CONNECTION WITH THIS ANNUAL REPORT ON FORM 10-K. ACCORDINGLY, THIS REPORT HAS NOT BEEN REISSUED BY ANDERSEN.

To the Shareholders and Board of

Directors of Pogo Producing Company:

We have audited the accompanying consolidated balance sheets of Pogo Producing Company (a Delaware corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, cash flows and shareholders equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Pogo Producing Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the financial statements, effective January 1, 2001, the Company changed its method of accounting for derivative instruments and hedging activities. In addition, effective January 1, 2000, the Company changed its method of accounting for product inventory.

ARTHUR ANDERSEN LLP

Houston, Texas

February 28, 2002

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2002	2001 (Expressed in thousands, except per share amounts)	2000
Revenues:			
Oil and gas	$ 746,988	$ 596,077	$ 479,202
Gains on sales	3,034	1,000	3,676
Other	1,419	13,040	15,113
Total	751,441	610,117	497,991
Operating Costs and Expenses:			
Lease operating	139,448	118,157	93,640
General and administrative	49,490	39,162	34,568
Exploration	4,783	23,373	15,291
Dry hole and impairment	26,999	26,945	28,608
Depreciation, depletion and amortization	287,809	206,609	131,151
Natural gas purchases and other	2,739	15,990	15,090
Total	511,268	430,236	318,348
Operating Income	240,173	179,881	179,643
Interest:			
Charges	(57,450)	(56,259)	(34,064)
Income	1,760	3,226	2,634
Capitalized	24,033	33,242	20,918
Minority Interest - Dividends and costs associated with mandatorily redeemable convertible preferred securities of a subsidiary trust	(4,140)	(9,999)	(9,965)
Foreign Currency Transaction Gain (Loss)	435	(524)	(3,174)
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	204,811	149,567	155,992
Income Tax Expense	(97,780)	(61,613)	(66,969)
Income Before Cumulative Effect of Change in Accounting Principle	107,031	87,954	89,023
Cumulative Effect of Change in Accounting Principle			(1,768)
Net Income	$ 107,031	$ 87,954	$ 87,255
Earnings (Loss) per Common Share:			
Basic			
Income before cumulative effect of change in accounting principle	$ 1.85	$ 1.72	$ 2.20
			(0.04)

Cumulative effect of change in accounting principle						
Net income	$	1.85	$	1.72	$	2.16
Diluted						
Income before cumulative						
effect of change in accounting principle	$	1.77	$	1.62	$	1.99
Cumulative effect of change in accounting principle						(0.04)
Net income	$	1.77	$	1.62	$	1.95
Dividends per Common Share	$	0.12	$	0.12	$	0.12

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2001
	(Expressed in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 134,449	$ 94,294
Accounts receivable	101,807	52,440
Other receivables	14,634	32,159
Federal income taxes receivable		27,441
Deferred income tax	20,041	25,712
Inventory - product	2,501	3,129
Inventories - tubulars	9,406	8,430
Price hedge contracts		34,275
Other	4,818	1,970
Total current assets	287,656	279,850
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	3,396,669	2,956,673
Unevaluated properties	141,094	257,158
Pipelines, at cost	775	775
Other, at cost	25,851	21,638
	3,564,389	3,236,244
Accumulated depreciation, depletion, and amortization		
Oil and gas	(1,389,976)	(1,133,560)
Pipelines	(744)	(739)
Other	(14,620)	(11,217)
	(1,405,340)	(1,145,516)
Property and equipment, net	2,159,049	2,090,728
Other Assets:		
Deferred income tax	2,416	13,359
Debt issue costs	11,368	13,136
Foreign value added taxes receivable	13,908	6,200
Other	17,196	20,706
	44,888	53,401
	$ 2,491,593	$ 2,423,979

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31, 2002	December 31, 2001
	(Expressed in thousands)	
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Accounts payable - operating activities	$ 41,102	$ 34,962
Accounts payable - investing activities	68,963	94,523
Accrued interest payable	11,096	11,450
Foreign income taxes payable	15,527	7,966
Accrued dividends associated with preferred securities of a subsidiary trust		813
Accrued payroll and related benefits	3,011	2,670
Deferred income tax	5,324	3,875
Price hedge contracts	2,433	-
Other	2,229	1,892
Total current liabilities	149,685	158,151
Long-Term Debt	722,903	792,561
Deferred Income Tax	526,897	488,639
Other Liabilities and Deferred Credits	14,324	14,657
Total liabilities	1,413,809	1,454,008
Commitments and Contingencies (Note 1)		
Minority Interests:		
Company-obligated mandatorily redeemable convertible preferred securities of a subsidiary trust, net of unamortized issue expenses		145,086
Shareholders Equity:		
Preferred stock, $1 par; 4,000,000 shares authorized		
Common stock, $1 par; 200,000,000 shares authorized, and 61,061,888 and 53,690,827 shares issued, respectively	61,062	53,691
Additional capital	822,526	659,227
Retained earnings	202,155	102,019
Accumulated other comprehensive income (loss)	(6,249)	10,272
Treasury stock (55,359 and 15,575 shares, respectively), at cost	(1,710)	(324)

Total shareholders equity		1,077,784		824,885
	$	2,491,593	$	2,423,979

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2002	**2001**	**2000**
	(Expressed in thousands)		
Cash flows from operating activities:			
Cash received from customers	$ 701,429	$ 625,538	$ 446,184
Income taxes received	25,884	1,381	6,000
Cash received (paid) related to price hedge contracts	14,931	20,142	(24,022)
Operating, exploration and general and administrative expenses paid	(199,104)	(205,004)	(152,979)
Interest paid	(55,526)	(48,458)	(32,028)
Income taxes paid	(19,287)	(31,115)	(9,444)
Value added taxes (paid) received	(7,708)	1,062	4,763
Other	5,860	4,530	585
Net cash provided by operating activities	466,479	368,076	239,059
Cash flows from investing activities:			
Capital expenditures	(368,466)	(386,164)	(139,062)
Proceeds from the sale of property and tubular stock	4,215	9,243	3,745
Acquisition of NORIC, net of $21,235,000 cash acquired		(323,476)	
Purchase of proved reserves		(2,714)	(8,393)
Proceeds from the sale of Canadian subsidiary		13,739	-
Net cash used in investing activities	(364,251)	(689,372)	(143,710)
Cash flows from financing activities:			
Proceeds from issuance of new debt		200,000	
Borrowings under senior debt agreements	703,077	1,322,990	67,000
Payments under senior debt agreements	(773,080)	(1,093,000)	(77,000)
Payment of North Central senior debt acquired		(78,600)	
Proceeds from exercise of stock options	20,154	7,469	6,115
Payment of preferred dividends of a subsidiary trust	(4,850)	(9,750)	(9,750)
Payment of cash dividends on common stock	(6,895)	(6,047)	(4,852)
Payment of financing issue costs and other	(329)	(8,720)	(135)
Net cash provided by (used in) financing activities	(61,923)	334,342	(18,622)
Effect of exchange rate changes on cash	(150)	(262)	(1,484)
Net increase in cash and cash equivalents	40,155	12,784	75,243
Cash and cash equivalents at the beginning of the year	94,294	81,510	6,267
Cash and cash equivalents at the end of the year	$ 134,449	$ 94,294	$ 81,510
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 107,031	$ 87,954	$ 87,255
Adjustments to reconcile net income to net cash provided by operating activities			
Cumulative effect of change in accounting principle			1,768
Minority interest	4,140	9,999	9,965
Gains on sales	(3,034)	(1,000)	(3,676)

Depreciation, depletion and amortization	287,809	206,609	131,151
Dry hole and impairment	26,999	26,945	28,608
Interest capitalized	(24,033)	(33,242)	(20,918)
Price hedge contracts	17,589	5,550	(24,022)
Foreign currency transaction (gain) loss and other	728	524	3,174
Increase (decrease) in deferred income taxes	70,929	50,617	63,495
Change in assets and liabilities:			
(Increase) decrease in accounts receivable	(50,521)	40,436	(48,425)
Increase in federal income taxes receivable		(22,809)	
Decrease in inventory - product	173	12	601
(Increase) decrease in other current assets	(12,571)	(534)	1,062
(Increase) decrease in other assets	(6,784)	6,257	2,902
Increase (decrease) in accounts payable	6,170	(17,786)	5,447
Increase in foreign income taxes payable	33,610	3,684	
Increase (decrease) in accrued interest payable	(352)	4,010	(14)
Increase in accrued payroll and related benefits	343	385	132
Increase (decrease) in other current liabilities	6,377	(241)	624
Increase (decrease) in deferred credits	1,876	706	(70)
Net cash provided by operating activities	$ 466,479	$ 368,076	$ 239,059

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED STATEMENTS OF SHAREHOLDERS EQUITY

(Expressed in thousands)

	Common Stock (a)	Additional Capital	Retained Earnings (Deficit)	Accumulated Other Compre-hensive Income (Loss)	Treasury Stock	Share-holders Equity	Compre-hensive Income (Loss)
Balance at December 31, 1999	40,279	$ 291,909	$ (62,291)	$ (1,061)	$ (324)	$ 268,512	
Net income			87,255			87,255	$ 87,255
Exercise of stock options	315	5,754				6,069	
Shares issued as compensation	66	1,222				1,288	
Dividends ($0.12 per common share)			(4,852)			(4,852)	
Exchange loss on Canadian currency				(1)		(1)	(1)
Comprehensive income							$ 87,254
Balance at December 31, 2000	40,660	298,885	20,112	(1,062)	(324)	358,271	
Net income			87,954			87,954	$ 87,954
Shares issued for stock and debt of acquired company	12,615	351,729				364,344	
Exercise of stock options	378	7,718				8,096	
Shares issued as compensation	38	895				933	
Dividends ($0.12 per common share)			(6,047)			(6,047)	
Exchange gain on Canadian currency				389		389	389
Reclassification adjustment included in net income				673		673	(389)
Cumulative effect of change in accounting principle				(2,438)		(2,438)	(2,438)
Unrealized gains arising during the year on price hedge contracts				22,195		22,195	
Reclassification adjustment included in net income				(9,485)		(9,485)	
Net unrealized gains on price hedge contracts							12,710
Comprehensive income							$ 98,226
	53,691	$ 659,227	$ 102,019	$ 10,272	$ (324)	$ 824,885	

Balance at December 31, 2001							
Net income			107,031			107,031	$ 107,031
Exercise of stock options	1,022	23,460				24,482	
Shares issued as compensation	39	1,124				1,163	
Conversion of Trust Preferred Securities	6,310	138,715				145,025	
Dividends ($0.12 per common share)			(6,895)			(6,895)	
Shares received in satisfaction of note receivable					(1,386)	(1,386)	
Unrealized loss arising during the year on price hedge contracts				(14,155)		(14,155)	
Reclassification adjustment included in net income				(2,366)		(2,366)	
Net unrealized losses on price hedge contracts							(16,521)
Comprehensive income							$ 90,510
Balance at December 31, 2002	61,062	$ 822,526	$ 202,155	$ (6,249)	$ (1,710)	$ 1,077,784	

(a) Reflects both dollar and share amounts at $1.00 par value.

The accompanying notes to consolidated financial statements are an integral part hereof.

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Nature of Operations

Pogo Producing Company was incorporated in 1970. Pogo Producing Company and its subsidiaries (the Company) are engaged in oil and gas exploration, development, production and acquisition activities in the United States, both offshore in the Gulf of Mexico (primarily in federal waters offshore Louisiana and Texas) and onshore principally in the states of New Mexico, Texas, Louisiana and Wyoming. The Company also conducts exploration, development and production activities internationally in the Kingdom of Thailand (offshore in the Gulf of Thailand) and exploration activities in Hungary and the British and Danish sectors of the North Sea.

Use of Estimates

The preparation of these financial statements requires the use of certain estimates by management in determining the Company s assets, liabilities, revenues and expenses. Actual results could differ from such estimates. Depreciation, depletion and amortization of oil and gas properties and the impairment of oil and gas properties are determined using estimates of oil and gas reserves. There are numerous uncertainties in estimating the quantity of reserves and in projecting the future rates of production and timing of development expenditures. Oil and gas reserve engineering must be recognized as a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact way. Proved reserves of crude oil, condensate, natural gas and natural gas liquids are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions.

Principles of Consolidation

The consolidated financial statements include the accounts of Pogo Producing Company and its subsidiaries and affiliates, after elimination of all significant intercompany transactions. Majority owned subsidiaries are fully consolidated. Minority owned oil and gas affiliates are pro rata consolidated in the same manner as the Company accounts for its operating or working interest in oil and gas joint ventures.

Prior Year Reclassifications

Certain prior year amounts have been reclassified to conform with the current year presentation. Such reclassifications had no effect on the Company s operating income, net income or shareholders equity.

Foreign Currency

The U.S. dollar is the functional currency for all areas of operations of the Company with the exception of Hungary, where the functional currency is the legal tender of Hungary, currently the Forint. Accordingly, monetary assets and liabilities and items of income and expense denominated in a foreign currency are remeasured to U.S. dollars at the rate of exchange in effect at the end of each month or the average for the month, and the resulting gains or losses on foreign currency transactions are included in the consolidated statements of income for the period.

Revenue Recognition

The Company follows the sales (takes or cash) method of accounting for oil and gas revenues. Under this method, the Company recognizes revenues on production as it is taken and delivered to its purchasers. The volumes sold may be more or less than the volumes the Company is entitled to based on its ownership interest in the property. These differences result in a condition known in the industry as a production imbalance. At December 31, 2002, the Company had taken approximately 1,202 MMcf of natural gas less than it was entitled to based on its interest in certain properties, and approximately 1,062 MMcf more than its entitlement on other properties. Therefore, the Company is owed a net position of approximately 140 MMcf of natural gas based on its working interest ownership in such properties. The Company s crude oil imbalances are not significant. Such imbalances are reflected as adjustments to proved reserves and future cash flows in the unaudited supplementary oil and gas data included herein.

Inventory Product

Crude oil and condensate from the Company s producing fields located in the Kingdom of Thailand are produced into storage vessels and are sold and recognized as revenue periodically as economic quantities are accumulated. Effective January 1, 2000, the Company adopted the provisions of the Securities and Exchange Commission s (the Commission) Staff

Accounting Bulletin No. 101, Revenue Recognition. As a result, the Comission no longer accepts the oil and gas exploration and production industry s long-standing historical practice of recording such product inventories at their net realizable value. The cumulative effect of this change in accounting principle through December 31, 1999 ($1,768,000, net of tax benefits of $1,768,000) has been charged to earnings effective January 1, 2000. The product inventory at December 31, 2002 consists of approximately 202,397 barrels of crude oil and condensate, net to the Company s interest, and is carried at the Company s estimated average cost of $12.35 per barrel. The product inventory at December 31, 2001 consisted of approximately 260,087 barrels of crude oil and condensate, net to the Company s interest, and is carried at its estimated average cost of $12.03 per barrel.

Inventories Tubulars

Tubular inventories consist primarily of goods used in the Company s operations and are stated at the lower of average cost or market value.

Earnings per Share

Earnings per common share (basic earnings per share) are based on the weighted average number of shares of common stock outstanding during the periods. Earnings per common share and potential common share (diluted earnings per share) consider the effect of dilutive securities as set out below in thousands, except per share amounts.

	For the Year Ended December 31, 2002		
	Income	Shares	Per Share
Basic earnings per share	$ 107,031	57,963	$ 1.85
Effect of potential dilutive securities:			
Shares assumed issued from the exercise of options to purchase common shares, net of treasury shares assumed purchased from the proceeds, at the average market price for the period		980	
Interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $42.185 per share of the 2006 Notes	4,111	2,726	
Minority interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $23.75 per share of the Trust Preferred Securities (redeemed on June 3, 2002)	2,661	2,652	
Diluted earnings per share	$ 113,803	64,321	$ 1.77
Antidilutive securities:			
Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive	$	143	$ 38.00

	For the Year Ended December 31, 2001		
	Income	Shares	Per Share
Basic earnings per share	$ 87,954	51,031	$ 1.72
Effect of potential dilutive securities:			
Shares assumed issued from the exercise of options to purchase common shares, net of treasury shares assumed purchased from the proceeds, at the average market price for the period		749	
Interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $42.185 per share of the 2006 Notes	4,111	2,726	
Minority interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $23.75 per share of the Trust Preferred Securities	6,338	6,316	
Diluted earnings per share	$ 98,403	60,822	$ 1.62
Antidilutive securities:			
Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive	$	266	$ 33.75

	For the Year Ended December 31, 2000				
		Income (a)	Shares		Per Share
Basic earnings per share	$	89,023	40,445	$	2.20
Effect of potential dilutive securities:					
Shares assumed issued from the exercise of options to purchase common shares, net of treasury shares assumed purchased from the proceeds, at the average market price for the period			668		
Interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $42.185 per share of the 2006 Notes		4,111	2,726		
Minority interest expense incurred, net of taxes, and shares issued related to the assumed conversion at $23.75 per share of the Trust Preferred Securities		6,338	6,316		
Diluted earnings per share	$	99,472	50,155	$	1.99

(a) Represents income before cumulative effect of change in accounting principle

Antidilutive securities:					
Shares assumed not issued from options to purchase common shares as the exercise prices are above the average market price for the period or the effect of the assumed exercise would be antidilutive	$		219	$	34.93

Oil and Gas Activities and Depreciation, Depletion and Amortization

The Company follows the successful efforts method of accounting for its oil and gas activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Proved oil and gas properties are reviewed when circumstances suggest the need for such a review and, if required, the proved properties are written down to their estimated fair value. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Estimated fair value includes the estimated present value of all reasonably expected future production, prices, and costs. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated as successful. Other exploratory costs are expensed as incurred. The provision for depreciation, depletion and amortization is based on the capitalized costs as determined above, plus future cost to abandon offshore wells and platforms, and is computed on a cost center by cost center basis using the units of production method, with lease acquisition costs amortized over total proved reserves and other costs amortized over proved developed reserves. The Company generally creates cost centers on a field-by-field basis for oil and gas activities in the Gulf of Mexico and the Gulf of Thailand. Generally, the Company establishes cost centers on the basis of an oil or gas trend or play for its onshore oil and gas activities. As described further below, the Company s method of accounting for asset retirement obligations (i.e. future abandonment costs) changed effective January 1, 2003.

The Company has an ongoing asset rationalization process. In connection with this process, the Company has from time to time disposed of certain non-core properties and other assets that it considers to be under performing, to have little or no remaining upside potential, or which face significant future expenditures that would result in an unacceptable rate of return. Refer to the captions Gains on sales in the Consolidated Statements of Income and Proceeds from the sale of property and tubular stock in the Consolidated Statements of Cash Flows.

Other properties and equipment are depreciated using a straight-line method in amounts which, in the opinion of management, are adequate to allocate the cost of the properties over their estimated useful lives.

Consolidated Statements of Cash Flows

For the purpose of cash flows, the Company considers all highly liquid investments with a maturity date of three months or less when purchased to be cash equivalents. Significant transactions may occur which do not directly affect cash balances and, as such, are not disclosed in the Consolidated Statements of Cash Flows. Certain such non-cash transactions are disclosed in the Consolidated Statements of Shareholders Equity, including shares issued upon conversion of Trust Preferred Securities

(Note 4), shares issued as compensation, and shares issued for stock and debt of an acquired company. The shares issued for stock of an acquired company are also discussed in the following Acquisition section of this note.

Commitments and Contingencies

The Company has commitments for operating leases (primarily for office space) in Houston, Midland, Fort Worth, Bangkok, Budapest, other equipment (including gas compressors) and for an FPSO and FSO in the Gulf of Thailand. Rental expense for office space was $2,821,000 in 2002, $2,623,000 in 2001, and $1,911,000 in 2000. Rental expense for other equipment was $2,022,000 in 2002, $654,000 in 2001 and $500,000 in 2000. Expenses for the FPSO lease were approximately $10,600,000 in 2002 and 2001 and $11,100,000 in 2000. Expenses for the FSO lease were approximately $4,000,000 in each of the years 2002, 2001 and 2000.

Future minimum lease payments related to the Company s operating leases at December 31, 2002 are approximately $21,700,000 in 2003; $21,500,000 in 2004; $21,400,000 in 2005; $21,300,000 in 2006; $18,100,000 in 2007 and $46,700,000 thereafter. Where rented equipment such as compressors is considered essential to the operation of the lease, the Company has assumed that such equipment will be leased for the estimated productive life of the reserves, even if the contract terminates prior to such date.

Acquisition

On March 14, 2001, the merger of the Company and NORIC was consummated. As a result of the merger, the Company acquired all of the outstanding capital stock of North Central which was the principal asset of NORIC. North Central was an independent domestic oil and gas exploration and production company. The merger was accounted for using the purchase method of accounting. Accordingly, the purchase price was allocated to the net assets acquired based on their estimated fair values at the date of acquisition. Commencing March 14, 2001, North Central s operations were consolidated with the operations of the Company. Pursuant to the merger agreement among the Company and NORIC and certain former NORIC shareholders, the former shareholders received 12,615,816 shares of the Company s common stock and approximately $344,711,000 in cash. In addition, at the closing all the $78,600,000 principal amount of North Central s existing bank debt was repaid.

The following summary presents unaudited pro forma consolidated results of operations as if the acquisition had occurred at the beginning of each period presented. The pro forma results are for illustrative purposes only and include adjustments in addition to the pre-acquisition historical results of North Central, such as increased depreciation, depletion and amortization expense resulting from the allocation of fair value to oil and gas properties acquired and increased interest expense on acquisition debt. The unaudited pro forma information (presented in thousands of dollars, except per share amounts) is not necessarily indicative of the operating results that would have occurred had the acquisition been consummated at those dates, nor are they necessarily indicative of future operating results.

	Year Ended December 31,	
	2001	**2000**
Revenues	$ 668,480	$ 643,091
Income before cumulative effect of change in accounting principle	$ 104,348	$ 89,608
Net income	$ 104,348	$ 87,840

Earnings per share:		
Basic -		
Income before cumulative effect of change in accounting principle	$ 1.95	$ 1.69
Net income	$ 1.95	$ 1.66
Diluted -		
Income before cumulative effect of change in accounting principle	$ 1.81	$ 1.48
Net income	$ 1.81	$ 1.45

Income Taxes

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective. Deferred tax assets are reduced by a valuation allowance for the amount of any tax benefit we do not expect to be realized. Note 2 contains information about the Company s income taxes, including the components of income tax provision and the composition of deferred income tax assets and liabilities.

Price Risk Management

The Company from time to time enters into commodity price hedging contracts with respect to its oil and gas production to achieve a more predictable cash flow, as well as reduce its exposure to price volatility. For periods prior to 2001, the Company accounted for such contracts as hedges, in accordance with Statement of Financial Accounting Standards No. 80 (SFAS 80). Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging Activities (SFAS 133).

Accounting for Commodity Price Hedging Contracts prior to the adoption of SFAS 133:

For periods prior to the adoption of SFAS 133, the Company recognized gains and losses on commodity price hedging contracts in revenue in the period in which the underlying production was delivered. In 2000, the Company hedged 16,910 MMcf of gas and 1,509,500 barrels of crude oil (25,967 equivalent MMcf) or approximately 21% of its equivalent 2000 production and recorded hedge losses of $11,549,000 in connection with its natural gas contracts and hedge losses of $9,976,000 in connection with its crude oil contracts

Accounting for Commodity Price Hedging Contracts after the adoption of SFAS 133:

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS 133. In June 2000, the FASB issued SFAS 138, Accounting for Derivative Instruments and Hedging Activities, an amendment of FASB Statement No. 133. SFAS 133, as amended, established accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. The statement requires that changes in the derivative s fair value be recognized currently in earnings unless specific hedge criteria are met. Special accounting for qualifying hedges allows a derivative s gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting. Based on the nature of the Company s derivative instruments currently outstanding and the historical volatility of oil and gas commodity prices, the Company expects that SFAS 133 could increase volatility in the Company s earnings and other comprehensive income for future periods.

SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings.

SFAS 133 requires that as of the date of initial adoption, the difference between the fair value of derivative instruments and the previous carrying amount of these derivatives be recorded in net income or other comprehensive income, as appropriate, as the cumulative effect of a change in accounting principle. The Company determined that the cumulative effect of adopting SFAS 133 should be recorded in other comprehensive income. The Company adopted SFAS 133 effective January 1, 2001 and recorded an unrealized loss of $2,438,000, net of deferred taxes of $1,313,000, in other comprehensive income (loss).

Accounting for Stock-Based Compensation:

Prior to January 1, 2003, the Company accounted for employee stock-based compensation using the intrinsic value recognition provisions of APB Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations. Under this method, the Company recognizes no compensation expense for stock options granted when the exercise price of the options is equal to or greater than the quoted market price of the Company s common stock on the grant date. Effective January 1, 2003, the Company has adopted the fair value recognition provisions of Statement of Financial Accounting Standards No. 123, Accounting for Stock Based Compensation (SFAS 123) and the prospective method transition provisions of Statement of Financial Accounting Standards No. 148, Accounting for Stock Based Compensation Transition and Disclosure an amendment of FAS No. 123 (SFAS 148) for all employee awards granted, modified or settled after January 1, 2003.

The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS 123 to employee stock-based compensation (in thousands of dollars, except per share amounts):

	2002	2001	2000
Net income, as reported	$ 107,031	$ 87,954	$ 87,255
Deduct: Total employee stock-based compensation expense, determined under fair value method for all awards, net of relatred tax effects	(5,710)	(4,413)	(2,932)
Pro forma	$ 101,321	$ 83,541	$ 84,323
Earnings per share:			
Basic - as reported	$ 1.85	$ 1.72	$ 2.16
Basic - pro forma	$ 1.75	$ 1.65	$ 2.12
Diluted - as reported	$ 1.77	$ 1.62	$ 1.95
Diluted - pro forma	$ 1.68	$ 1.57	$ 1.91

The fair value of grants was estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used in 2002, 2001 and 2000, respectively: risk free interest rates of 4.20%, 4.85% and 6.03%, expected volatility of 33.9%, 44.41% and 42.85%, dividend yields of 0.51%, 0.49% and 0.59%, and an expected life of the options of seven, six and five years.

Recent Accounting Pronouncements

The Financial Accounting Standards Board (FASB) has issued several new pronouncements, including Statement of Financial Accounting Standards No. 143 (SFAS 143), Accounting for Asset Retirement Obligations , Statement of Financial Accounting Standards No. 146, Accounting for Exit or Disposal Activities (SFAS 146) and SFAS 148.

SFAS 143. SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The Company adopted this standard as required on January 1, 2003 and will record an after-tax non-cash charge to earnings of approximately $4 million representing the cumulative effect of the change in accounting principle.

SFAS 146. SFAS 146 addresses significant issues regarding the recognition, measurement and reporting of costs that are associated with exit and disposal activities, including restructuring activities that are currently accounted for pursuant to the guidance set forth in EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity . The Company adopted this standard as required on January 1, 2003. Implementation of the new standard had no impact upon adoption and is not expected to have a material financial statement impact on the Company.

SFAS 148. SFAS 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for employee stock-based compensation. In addition, SFAS 148 requires prominent disclosures in both annual and interim financial statements about the method of accounting for employee stock-based compensation and the effect of the method used on reported results. These disclosure provisions have been adopted by the Company in connection with this Form 10-K. As previously described, effective January 1, 2003, the Company adopted the fair value recognition provisions of SFAS 123, prospectively to all employee awards granted, modified or settled after January 1, 2003. Adoption of the fair value recognition provisions of SFAS 123 will result in compensation expense for stock option grants. The impact of applying the fair value recognition standard on the Company s future results of operation is anticipated to be consistent with that shown in the historical pro-forma disclosures above. However, since the Company has elected a prospective transition method, the impact on 2003 net income will be limited to awards granted after January 1, 2003, and no compensation expense will be recognized on unvested awards outstanding at January 1, 2003.

(2) Income Taxes

The components of income before income taxes for each of the three years in the period ended December 31, 2002, are as follows (expressed in thousands):

	2002	2001	2000
United States	$ 101,349	$ 81,619	$ 67,967
Foreign	103,462	67,948	88,025
Income before income taxes and cumulative effect of change in accounting principle	$ 204,811	$ 149,567	$ 155,992

The components of income tax expense (benefit) for each of the three years in the period ended December 31, 2002, are as follows (expressed in thousands):

	2002	2001	2000
Current			
United States	$ 15,497	$ -	$ 9,000
Foreign	11,351	10,996	-
Deferred			
United States	32,451	59,823	12,392
Foreign	38,481	(9,206)	45,577
Income tax expense	$ 97,780	$ 61,613	$ 66,969

Total income tax expense for each of the three years in the period ended December 31, 2002, differs from the amounts computed by applying the statutory federal income tax rate to income before taxes as follows (expressed as a percent of pretax income):

	2002	2001	2000
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increases (reductions) resulting from:			
Foreign income taxed at different rates	7.8	11.3	8.7
Recognition of previously unbenefitted loss carryforwards	-	(20.4)	-
U.S. taxes on repatriation of foreign earnings	2.3	5.7	-
State income taxes, net of federal benefit	0.5	4.0	-
Other	2.2	5.6	(0.8)
	47.8%	41.2%	42.9%

The principal components of the Company s deferred income tax assets and liabilities at December 31, 2002 and 2001 (expressed in thousands) are as follows:

	December 31,	
	2002	2001
Deferred tax assets:		
Foreign net operating loss carry forwards	$ 22,457	$ 39,071
Tax basis in excess of book basis for price hedge contracts	8,895	
Other		5,055
	31,352	44,126
Deferred tax liabilities:		
Book basis in excess of tax basis for oil and gas properties and equipment	(538,132)	(490,496)
Book basis in excess of tax basis for price hedge contracts		(5,531)
Other	(2,984)	(1,542)
	(541,116)	(497,569)
Net deferred tax liability	$ (509,764)	$ (453,443)

Book basis in excess of tax basis for oil and gas properties and equipment primarily results from differing methodologies for recording property costs and depreciation, depletion and amortization under United States generally accepted accounting principles and income tax reporting. In addition, the Company recorded a deferred tax liability resulting from book and tax basis differences of the acquired NORIC net assets (see Acquisition under Note 1).

As of December 31, 2002, the Company has foreign net operating loss carryforwards of approximately $53,504,000 which are available to offset future income tax. These losses are primarily related to the Company s Thailand operations, and will begin to expire in 2007.

Where the Company s present intention is to reinvest the unremitted earnings in its foreign operations, the Company does not provide for U.S. income taxes on unremitted earnings of foreign subsidiaries. Unremitted earnings of foreign subsidiaries for which U.S. income taxes have not been provided are approximately $91,566,000 at December 31, 2002. It is not practical to determine the amount of U.S. income taxes that would be payable upon remittance of the assets that represent those earnings.

During the third quarter of 2001, the Company reevaluated its global tax and cash position, including estimates regarding the realization of its Thailand operating loss carryforwards as well as its ability to indefinitely reinvest all unremitted foreign earnings in its foreign operations. Based on the Company s future expectations for its Thailand operations, the Company believes that it is more likely than not that its remaining Thailand operating loss carryforwards will be realized and, therefore, reversed the remaining valuation allowance accordingly. In addition, the Company provided for U.S. income taxes on the unremitted earnings from a portion of its Thailand operations determined to be subject to repatriation. However, where the Company s continued intention is to reinvest the unremitted earnings of a foreign subsidiary in foreign operations, the Company will continue to not provide U.S. income taxes on those earnings.

53

(3) Long-Term Debt

Long-term debt at December 31, 2002 and 2001, consists of the following (dollars expressed in thousands):

	December 31,	
	2002	2001
Senior debt -		
Bank revolving credit agreement:		
LIBOR based loans, borrowings at December 31, 2002 and 2001 at interest rates of 2.5625% and 3.1875%, respectively	$ 135,000	$ 185,000
Prime based loans, borrowings at December 31, 2001 at an interest rate of 4.75%		10,000
Swing line money market loans, borrowings at December 31, 2001 at an interest rate of 3.3125%		10,000
Banker s Acceptance loans, borrowings at December 31, 2002 and 2001 at interest rates of 2.2765% and 2.45%, respectively	24,987	24,990
Total senior debt	159,987	229,990
Subordinated debt -		
8 3/4% Senior subordinated notes, due 2007	100,000	100,000
10 3/8% Senior subordinated notes, due 2009	150,000	150,000
8 1/4% Senior subordinated notes, due 2011	200,000	200,000
5 1/2% Convertible subordinated notes, due 2006	115,000	115,000
Total subordinated debt	565,000	565,000
Unamortized discount on 2009 Notes	(2,084)	(2,429)
Long-term debt	$ 722,903	$ 792,561

On March 8, 2001, the Company entered into the Credit Facility, a reserve based revolving credit facility. The Credit Facility provides for a $515,000,000 revolving credit facility until March 7, 2006. The amount that may be borrowed may not exceed a borrowing base which is determined semi-annually and is calculated based upon substantially all of the Company s proved oil and gas properties. The borrowing base is currently established at $500,000,000. The Credit Facility is governed by various financial and other covenants, including requirements to maintain positive working capital (excluding current maturities of debt) and a fixed charge coverage ratio, and limitations on the creation of liens, commodity hedging above specified limits, the prepayment of subordinated debt, the payment of dividends, mergers and consolidations, investments and asset dispositions. In addition, the Company is prohibited from pledging borrowing base properties as security for other debt. The Company has pledged the stock of North Central and its inter-company receivables with North Central as collateral for its obligations under the Credit Facility. The Credit Facility also permits short-term swing-line loans and the issuance of up to $50,000,000 in letters of credit as part of the facility. Borrowings under the Credit Facility bear interest, at the Company s option, at a base (prime) rate plus a variable margin (currently none) or LIBOR plus a variable margin (currently l.125%). The margin varies as a function of the percentage of the borrowing base utilized and, with respect to the LIBOR rate, the Company s credit rating. A commitment fee on the unborrowed amount that is currently available under the Credit Facility is also charged based on the percentage of the borrowing base that is being utilized.

Under a Master Banker s Acceptance Agreement between the Company and one of its lenders, the lender makes available to the Company banker s drafts on an uncommitted basis up to $25,000,000. Drafts drawn under this agreement are reflected as long-term debt on the Company s balance sheet because the Company currently has the ability and intent to reborrow such amount under the Credit Facility. The Company s 2007 Notes, 2009 Notes, and 2011 Notes may restrict all or a portion of the amounts that may be borrowed under the Master Banker s Acceptance Agreement as senior debt. The Master Banker s Acceptance Agreement permits either party to terminate the letter agreement at any time upon five-business days notice.

On May 22, 1997, the Company issued $100,000,000 of principal amount of 2007 Notes. The 2007 Notes bear interest at a rate of 8 ¾ %, payable semi-annually in arrears on May 15 and November 15 of each year. The 2007 Notes are general unsecured senior subordinated obligations of the Company and are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the Credit Facility and its Banker s Acceptances, are equal in right of payment to the 2009 Notes and the 2011 Notes, but are senior in right of payment to the Company s subordinated indebtedness which currently includes the 2006 Notes. The Company, at its option, may redeem the 2007 Notes in whole or in part, at any time, at a redemption price of 104.375% of their principal value. The redemption premium will decline to 102.917% on May 15, 2003 and continue to decrease over the next several years. The indenture governing the 2007

Notes also imposes certain covenants on the Company that are substantially identical to the covenants contained in the indenture governing the 2011 Notes described below.

On January 15, 1999, the Company issued $150,000,000 principal amount of 2009 Notes. The 2009 Notes bear interest at a rate of 10 3/8%, payable semi-annually in arrears on February 15 and August 15 of each year. The 2009 Notes are generally unsecured senior subordinated obligations of the Company, are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the Credit Facility and its Banker s Acceptances, are equal in right of payment to the 2007 Notes and 2011 Notes, but are senior in right of payment to its subordinated indebtedness, which currently includes the 2006 Notes. The Company, at its option, may redeem the 2009 Notes in whole or in part, at any time on or after February 15, 2004, at a redemption price of 105.188% of their principal value and decreasing percentages thereafter. The indenture governing the 2009 Notes also imposes certain covenants on the Company that are substantially identical to the covenants contained in the indenture governing the 2011 Notes, described below.

On April 10, 2001, the Company issued $200,000,000 principal amount of 2011 Notes. The 2011 Notes bear interest at a rate of 8 ¼ %, payable semi-annually in arrears on April 15 and October 15 of each year. The 2011 Notes are general unsecured senior subordinated obligations of the Company, are subordinated in right of payment to the Company s senior indebtedness, which currently includes the Company s obligations under the Credit Facility and its Banker s Acceptances, are equal in right of payment to the 2007 Notes and the 2009 Notes, but are senior in right of payment to the Company s subordinated indebtedness, which currently includes the 2006 Notes. The Company, at its option, may redeem the 2011 Notes in whole or in part, at any time on or after April 15, 2006, at a redemption price of 104.125% of their principal value and decreasing percentages thereafter. The indentures governing the 2011 Notes also imposes certain covenants on the Company including covenants limiting: incurrence of indebtedness including senior indebtedness; restricted payments; the issuance and sales of restricted subsidiary capital stock; transactions with affiliates; liens; disposition of proceeds of assets sales; non-guarantor restricted subsidiaries; dividends and other payment restrictions affecting restricted subsidiaries; and merger, consolidations and the sale of assets.

The outstanding principal amount of 2006 Notes was $115,000,000 as of December 31, 2002. The 2006 Notes bear interest at a rate of 5 ½ %, payable semi-annually in arrears on June 15 and December 15 of each year. The 2006 Notes are convertible into Common Stock at $42.185 per share subject to adjustment upon the occurrence of certain events. The 2006 Notes are general unsecured subordinated obligations of the Company, and are subordinated in right of payment to the Company s senior indebtedness which currently includes the Company s obligations under the Credit Facility and its Banker s Acceptances, its senior subordinated indebtedness, which currently includes the 2011 Notes, the 2009 Notes and the 2007 Notes. The 2006 Notes are currently redeemable at the option of the Company, in whole or in part, at any time, at a redemption price of 102.2% of their principal. The redemption premium will decline over the next several years.

The Company currently has no maturities or sinking fund requirements during the next three years in connection with the above long-term debt. In 2006, maturities of $274,987,000 will become due consisting of the senior debt currently outstanding and the outstanding principal of the 2006 Notes. In 2007, maturities of $100,000,000 will become due consisting of the outstanding principal of the 2007 Notes.

(4) Minority Interest

Pogo Trust I, a subsidiary of the Company, called its 6½% Cumulative Quarterly Income Convertible Preferred Securities due 2029 (the Trust Preferred Securities) for redemption on June 3, 2002. Prior to their redemption, holders of 2,997,196 of the 3,000,000 outstanding Trust Preferred Securities converted their Trust Preferred Securities, representing $149,850,000 face value of Trust Preferred Securities, into 6,309,972 shares of the Company s common stock. In connection with the redemption, Pogo Trust I paid a total of $147,000 to former holders of the Trust Preferred Securities. Subsequent to June 3, 2002, there were no Trust Preferred Securities outstanding.

The amounts recorded under Minority Interests Dividends and costs associated with preferred securities of a subsidiary trust principally reflect cumulative dividends and, to a lesser extent, the amortization of issuance expenses related to the offering and sale of the Trust Preferred Securities.

(5) Business Segment Information

The Company s reportable segments, which are primarily in the business of natural gas and crude oil exploration and production, are identified below. The accounting policies of the segments are the same as those described in the summary of significant policies. The Company evaluates performance based on profit or loss from operations before income and expense items incidental to oil and gas operations and income taxes. Financial information by operating segment is presented below:

	Total Company	Oil and Gas	Pipelines	Corporate & Other
		(Expressed in thousands)		
Long-Lived Assets:				
As of December 31, 2002:				
United States	$ 1,780,431	$ 1,772,742	$ 31	$ 7,658
Kingdom of Thailand	378,260	374,775		3,485
Other	358	271		87
Total	$ 2,159,049	$ 2,147,788	$ 31	$ 11,230
As of December 31, 2001:				
United States	$ 1,748,046	$ 1,741,035	$ 36	$ 6,975
Kingdom of Thailand	342,411	338,965		3,446
Canada and other	271	271		
Total	$ 2,090,728	$ 2,080,271	$ 36	$ 10,421
Capital Expenditures:				
(including interest capitalized)				
For the year ended December 31, 2002:				
United States	$ 280,391	$ 277,147	$	$ 3,244
Kingdom of Thailand	101,299	101,299		
Other				
Total	$ 381,690	$ 378,446	$	$ 3,244
For the year ended December 31, 2001:				
United States	$ 1,458,549	$ 1,453,756	$	$ 4,793
Kingdom of Thailand	73,192	73,192		
Canada and other	3,071	3,071		
Total	$ 1,534,812	$ 1,530,019	$	$ 4,793
Revenues:				
For the year ended December 31, 2002				
United States	$ 538,601	$ 534,304	$ 79	$ 4,218
Kingdom of Thailand	212,763	212,684		79
Other	77			77
Total	$ 751,441	$ 746,988	$ 79	$ 4,374
For the year ended December 31, 2001				
United States	$ 422,120	$ 408,514	$ 12,037	$ 1,569
Kingdom of Thailand	183,074	183,005		69
Canada	4,923	4,558		365

Total	$	610,117	$	596,077	$	12,037	$	2,003
For the year ended December 31, 2000								
United States	$	309,602	$	291,266	$	15,277	$	3,059
Kingdom of Thailand		182,965		183,060				(95)
Canada		5,424		4,876				548
Total	$	497,991	$	479,202	$	15,277	$	3,512

56

	Total Company		Oil and Gas		Pipelines		Corporate & Other
			(Expressed in thousands)				
Depreciation, depletion, and amortization expense:							
For the year ended December 31, 2002							
United States	$	221,646	$	218,636	$	6	$ 3,004
Kingdom of Thailand		66,099		65,229			870
Other		64					64
Total	$	287,809	$	283,865	$	6	$ 3,938
For the year ended December 31, 2001							
United States	$	142,643	$	140,304	$	231	$ 2,108
Kingdom of Thailand		61,814		61,243			571
Canada and other		2,152		2,129			23
Total	$	206,609	$	203,676	$	231	$ 2,702
For the year ended December 31, 2000							
United States	$	77,828	$	76,516	$	247	$ 1,065
Kingdom of Thailand		51,250		50,968			282
Canada		2,073		1,992			81
Total	$	131,151	$	129,476	$	247	$ 1,428
Operating income (loss):							
For the year ended December 31, 2002							
United States	$	138,934	$	134,482	$	234	$ 4,218
Kingdom of Thailand		103,021		102,942			79
Other		(1,782)		(1,859)			77
Total	$	240,173	$	235,565	$	234	$ 4,374
For the year ended December 31, 2001							
United States	$	113,976	$	117,096	$	(72)	$ (3,048)
Kingdom of Thailand		76,493		76,424			69
Canada and other		(10,588)		(10,953)			365
Total	$	179,881	$	182,567	$	(72)	$ (2,614)
For the year ended December 31, 2000							
United States	$	86,996	$	84,491	$	(554)	$ 3,059
Kingdom of Thailand		92,735		92,830			(95)
Canada		(88)		(636)			548
Total	$	179,643	$	176,685	$	(554)	$ 3,512

(6) Sales to Major Customers

The Company is an oil and gas exploration and production company that generally sells its oil and gas to numerous customers on a month-to-month basis. For purposes of comparison, 2002 sales have been presented for those customers who have in either of the previous two years exceeded 10% of revenues (expressed in thousands):

	2002	2001	2000
Enron Corp. and affiliates	$ 5,594	$ 96,970	$ 66,083

(7) Credit Risk

Substantially all of the Company s accounts receivable at December 31, 2002 and 2001, result from oil and gas sales and joint interest billings to other companies in the energy industry. This concentration of customers and joint interest owners may impact the Company s overall credit risk, either positively or negatively, in that these entities may be similarly affected by industry-wide changes in economic or other conditions. Such receivables are generally not collateralized. As of December 31, 2002 and 2001, the Company had provided reserves for receivables from customers and joint interest owners that are considered doubtful of collection of $5,542,000 and $4,519,000, respectively.

During 2001 and 2002, the Company sold a portion of its oil and natural gas production to Enron Corp. and affiliated companies. On December 2, 2001, Enron Corp. declared bankruptcy. Prior to such bankruptcy filing, the Company requested financial assurances from an Enron affiliate concerning performance under a natural gas sales agreement with North Central. The requested assurances were not provided and North Central subsequently suspended performance under the contract and ceased selling to such Enron affiliate. As of December 31, 2002, the Company had an accounts receivable of $1,538,000, net of an applicable reserve, for physical sales of natural gas during November 2001 to such Enron affiliate. During 2002, the Company sold $5,594,000 to EOTT, an affiliated company of Enron Corp.

A substantial portion of the Company s oil and gas operations are conducted in Southeast Asia, and a substantial portion of its natural gas and liquids hydrocarbon production are sold there. Southeast Asia in general, and the Kingdom of Thailand in particular, experienced severe economic difficulties in 1997 and 1998 which were characterized by sharply reduced economic activity, illiquidity, highly volatile foreign currency exchange rates and unstable stock markets. Since that time, the economic situation in the Kingdom of Thailand has generally stabilized. However, as with most emerging market economies, the Thai economy remains particularly sensitive to worldwide economic trends. The economic health of the Thai economy and its effect on the volatility of the Thai Baht against the U.S. dollar will continue to have a material impact on the Company s operations in the Kingdom of Thailand, together with the prices that the company receives for its oil and natural gas production there.

As a result of the substantial oil and gas operations and earnings from its Thailand operations, the Company generates a significant amount of cash which is maintained in various bank accounts with multi-national banks for future foreign investment. These balances are diversified between cash and other short-term investments.

(8) Employee Benefits

The Company has a tax-advantaged savings plan in which all U.S. salaried employees may participate. Under such plan, a participating employee may allocate up to 10% of their salary, up to a maximum allowed by law, and the Company will then match the employee s contribution on a dollar for dollar basis up to the lesser of 6% of the employees salary or $11,000 in 2002. Funds contributed by the employee and the matching funds contributed by the Company are held in trust by a bank trustee in six separate funds. Amounts contributed by the employee and earnings and accretions thereon may be used to purchase shares of common stock, invest in a money market fund or invest in four stock, bond, or blended stock and bond mutual funds according to instructions from the employee. Matching funds contributed to the savings plan by the Company are invested only in Company common stock. The Company contributed $1,068,000 to the savings plan in 2002, $928,000 in 2001, and $886,000 in 2000.

The Company has adopted a trusteed retirement plan for its U.S. salaried employees. The benefits are based on years of service and the employee s average compensation for five consecutive years within the final ten years of service which produce the highest average compensation. The Company makes annual contributions to the plan in the amount of retirement plan cost accrued or the maximum amount that can be deducted for federal income tax purposes. The plan is invested approximately 99% in equities and 1% in cash equivalents. Although the Company has no obligation to do so, the Company currently provides full medical benefits to its retired U.S. employees and dependents. For current employees, the Company assumes all or a portion of post-retirement medical and term life insurance costs based on the employee s age and length of service with the Company. The post-retirement medical plan has no assets and is currently funded by the Company on a pay-as-you-go basis.

The following table sets forth the plans status (in thousands of dollars) as of December 31, 2002 and 2001.

	Retirement Plan		Post-Retirement Medical Plan	
	2002	2001	2002	2001
Change in benefit obligation				
Benefit obligation at beginning of year	$ 19,020	$ 14,979	$ 9,904	$ 8,002
Service cost	1,929	1,577	736	602
Interest cost	1,395	1,144	715	556
Plan amendments	348	499		
Acquisitions/divestitures				737
Benefits paid	(704)	(413)	(358)	(212)
Actuarial loss	2,309	1,234	4,070	219
Benefit obligation at end of year	$ 24,297	$ 19,020	$ 15,067	$ 9,904
Change in plan assets				
Fair value of plan assets at beginning of year	$ 33,465	$ 38,337	$	$
Actual return on plan assets	(5,721)	(4,145)		
Employer contributions			358	212
Benefits paid	(704)	(413)	(358)	(212)
Administrative expenses	(416)	(314)		
Fair value of plan assets at end of year	$ 26,624	$ 33,465	$	$
Reconciliation of funded status				
Funded status	$ 2,327	$ 14,445	$ (15,067)	$ (9,904)
Unrecognized actuarial loss (gain)	12,085	523	2,957	(1,113)
Unrecognized transition (asset) or obligation			913	1,217
Unrecognized past service cost	714	372		
Prepaid (accrued) benefit cost at year-end	$ 15,126	$ 15,340	$ (11,197)	$ (9,800)
Discount rate	6.50%	7.25%	6.50%	7.25%
Expected return on plan assets	8.50%	9.50%		
Rate of compensation increase	4.75%	4.75%		
Components of net periodic benefit cost				
Service cost	$ 1,929	$ 1,577	$ 736	$ 602
Interest cost	1,395	1,144	715	556
Expected return on plan assets	(3,116)	(3,593)		
Amortization of prior service cost	6	(43)		
Amortization of transition (asset) obligation		(26)	305	304
Recognized actuarial gain		(476)		(96)
	$ 214	$ (1,417)	$ 1,756	$ 1,366

For measurement purposes, a 13% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003. The rate is assumed to decrease gradually to 5% for 2012 and remain at that level thereafter. This compares to the amounts used for 2002 measurement purposes, where a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed, decreasing gradually to 5% for 2007 and remaining level thereafter.

Assumed health care cost trends have a significant effect on the amount reported for the health care plan. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in thousands):

	One Percentage Point			
		Increase		Decrease
Effect on total of service and interest cost components for 2002	$	260	$	(209)
Effect on year-end 2002 postretirement benefit obligation	$	2,349	$	(1,917)

(9) Stock-Based Compensation Plans

The Company s incentive plans authorize awards granted wholly or partly in common stock (including rights or options which may be exercised for or settled in common stock) to key employees and non-employee directors. Awards to employees of the Company may be made as grants of stock options, stock appreciation rights, stock awards, cash awards, performance awards or any combination thereof (collectively, Awards). Employee Awards generally become exercisable in three installments. Non-employee directors are granted options to purchase 10,000 shares of common stock on the first business day of June following such director s initial election or appointment and options to purchase 5,000 shares of common stock each year of their service as a director thereafter. Stock options, if not exercised, expire 10 years from the date of grant. A summary of the status of the Company s incentive plans as of December 31, 2002, 2001 and 2000, and changes during the years ended on those dates is presented below:

	Number of Options		Weighted Average Exercise Price
Outstanding, December 31, 1999	3,005,615	$	19.78
Granted in 2000	722,800	$	20.58
Exercised in 2000	(314,850)	$	15.33
Canceled in 2000	(5,942)	$	13.32
Outstanding, December 31, 2000	3,407,623	$	20.37
Exercisable, December 31, 2000	2,026,517	$	20.72
Available for grant, December 31, 2000	932,677		
Weighted-average fair value of options granted during 2000		$	9.58
Outstanding, December 31, 2000	3,407,623	$	20.37
Granted in 2001	1,035,400	$	25.35
Exercised in 2001	(377,764)	$	17.30
Canceled in 2001	(208,832)	$	21.75
Outstanding, December 31, 2001	3,856,427	$	21.93
Exercisable, December 31, 2001	2,267,561	$	21.09
Available for grant, December 31, 2001	898,520		
Weighted-average fair value of options granted during 2001		$	11.98
Outstanding, December 31, 2001	3,856,427	$	21.93

Granted in 2002	960,900	$	29.84
Exercised in 2002	(1,022,034)	$	19.72
Canceled in 2002	(61,847)	$	23.49
Outstanding, December 31, 2002	3,733,446	$	24.54
Exercisable, December 31, 2002	1,992,883	$	22.41
Available for grant, December 31, 2002	2,911,565		
Weighted-average fair value of options granted during 2002		$	12.43

The following table summarizes information about stock options outstanding at December 31, 2002

	Options Outstanding				Options Exercisable		
Range of Option Prices	Number Outstanding	Weighted Average Remaining Contractual Life (days)		Weighted Average Exercise Price	Number Exercisable		Weighted Average Exercise Price
$ 15.13 to $19.56	700,808	2,055	$	18.89	698,808	$	18.90
$ 20.31 to $24.81	1,800,403	2,599	$	22.63	1,028,633	$	21.93
$ 25.38 to $29.78	1,054,735	3,392	$	29.53	90,942	$	27.39
$ 31.18 to $33.94	58,500	2,772	$	32.17	55,500	$	32.20
$ 36.00	50,000	1,250	$	36.00	50,000	$	36.00
$ 40.63 to $41.00	69,000	1,626	$	40.92	69,000	$	40.92
Total	3,733,446	2,688	$	24.54	1,992,883	$	22.41

(10) Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value.

Cash and Cash Equivalents

Fair value is carrying value.

Receivables and Payables

Fair value approximates carrying value.

Derivative Financial Instruments

Fair value is carrying value.

Debt and Other

Instrument	Basis of Fair Value Estimate
Bank revolving credit agreement	Fair value was carrying value as of December 31, 2002 and 2001 based on the market value interest rates.
Banker s acceptance loans	Fair value was carrying value as of December 31, 2002 and 2001 based on the market value interest rates.
2007 Notes	Fair value was 104.25% and 102%, of carrying value as of December 31, 2002 and 2001, respectively, based on quoted market values.
2009 Notes	Fair value was 108% and 107.5%, of carrying value as of December 31, 2002 and 2001, respectively, based on quoted market values.
2011 Notes	Fair value was 105% and 101.25% of carrying value as of December 31, 2002 and 2001, respectively, based on quoted market value.
2006 Notes	Fair value was 106.71% and 95.625%, of carrying value as of December 31, 2002 and 2001, respectively, based on quoted market values.
Minority interest in company-obligated mandatorily redeemable preferred securities of a subsidiary trust	Fair value was 117.8% of carrying value as of December 31, 2001, based on quoted market values. This instrument was called for redemption by the Company on June 3, 2002.

The carrying value and estimated fair value of the Company s financial instruments at December 31, 2002 and 2001 (in thousands of dollars) are as follows:

	2002		2001	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Cash and cash equivalents	$ 134,449	$ 134,449	$ 94,294	$ 94,294
Receivables	$ 116,441	$ 116,441	$ 112,040	$ 112,040
Payables	$ (125,592)	$ (125,592)	$ (137,451)	$ (137,451)
Debt:				
Bank revolving credit agreement loans	$ (135,000)	$ (135,000)	$ (205,000)	$ (205,000)
Banker s acceptance loans	$ (24,987)	$ (24,987)	$ (24,990)	$ (24,990)
2007 Notes	$ (100,000)	$ (104,250)	$ (100,000)	$ (102,000)
2009 Notes	$ (147,916)	$ (162,000)	$ (147,571)	$ (161,250)
2011 Notes	$ (200,000)	$ (210,000)	$ (200,000)	$ (202,500)
2006 Notes	$ (115,000)	$ (122,711)	$ (115,000)	$ (109,969)
Minority interest in company obligated mandatorily redeemable preferred securities of a subsidiary trust	$	$	$ (150,000)	$ (176,700)

The Company occasionally enters into hedging contracts to minimize the impact of oil and gas price fluctuations. See Note 11 for a further discussion of these contracts.

(11) Hedging Activities

During 2002 and 2001, the Company recognized pre-tax gains of $3,640,000 ($2,367,000 after tax) and $14,592,000 ($9,485,000 after tax), respectively, from its price hedge contracts which are included in oil and gas revenues. No ineffectiveness on these hedge contracts was recognized in income. Unrealized losses on derivative instruments of $16,521,000 (net of deferred taxes of $8,896,000) have been reflected as a component of other comprehensive income for the year ended December 31, 2002. Based on the fair value of the hedge contracts as of December 31, 2002, the Company would reclassify additional pre-tax losses of approximately $9,614,000 (approximately $6,249,000 after taxes) from accumulated other comprehensive income (shareholders equity) to net income during the next twelve months.

As of December 31, 2002, the Company held various derivative instruments. During 2002, the Company entered into natural gas and crude oil option agreements referred to as collars . Collars are designed to establish floor and ceiling prices on anticipated future natural gas and crude oil production. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. While the use of these derivative instruments limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of derivatives also involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. Currently, the Company does not expect losses due to credit worthiness of its counterparties.

The gas hedging transactions are generally settled based upon the average of the reporting settlement prices on the NYMEX for the last three trading days of a particular contract month. The oil hedging transactions are generally settled based on the average of the reporting settlement prices for West Texas Intermediate on the NYMEX for each trading day of a particular calendar month. For any particular collar transaction, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor price for such transaction, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is above the ceiling price of such transaction.

The estimated fair value of these derivative instruments is based upon various factors that include closing exchange prices on the NYMEX, over-the-counter quotations, volatility and the time value of options. Further details related to the Company s hedging activities as of December 31, 2002, are as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor		Ceiling		Fair Value of Liability
Natural Gas Contracts (MMBtu) (a)						
Collar Contracts:						
January 2003 - December 2003	14,600	$	3.85	$	5.00	$ (2,127,192)
Crude Oil Contracts (Barrels)						
Collar Contracts:						
January 2003 - December 2003	3,650,000	$	25.00	$	30.00	$ (305,636)

(a) MMBtu means million British Thermal Units.

In January 2003, the Company entered into additional natural gas collars to establish floor and ceiling prices on anticipated future natural gas production. The Company has designated these contracts as cash flow hedges. Further details related to this hedging activity is as follows:

Contract Period and Type of Contract	Volume	NYMEX Contract Price Floor	Ceiling
Natural Gas Contracts (MMBtu)			
Collar Contracts:			
January 2003 - December 2003	6,680	$ 4.25	$ 7.00

POGO PRODUCING COMPANY & SUBSIDIARIES

UNAUDITED SUPPLEMENTARY FINANCIAL DATA

Oil and Gas Producing Activities

The results of operations from oil and gas producing activities exclude non-oil and gas revenues, general and administrative expenses, depreciation expense, interest charges, interest income and interest capitalized. Income tax (expense) or benefit was determined by applying the statutory rates to pretax operating results with adjustments for permanent differences.

	Total Company	United States	Kingdom of Thailand	Canada	Other
			(Expressed in thousands)		
			2002		
Revenues	$ 746,952	$ 534,268	$ 212,684	$	$
Lease operating expense	(139,466)	(101,219)	(38,247)		
Exploration expense	(4,783)	(4,161)	(544)		(78)(a)
Dry hole and impairment expense	(26,999)	(26,999)			
Depreciation, depletion and amortization expense	(283,865)	(218,636)	(65,229)		
Pretax operating results	291,839	183,253	108,664		(78)
Income tax (expense) benefit	(128,498)	(65,545)	(62,967)		14
Operating results	$ 163,341	$ 117,708	$ 45,697	$	$ (64)
			2001		
Revenues	$ 596,077	$ 408,514	$ 183,005	$ 4,558	$
Lease operating expense	(118,157)	(79,916)	(36,993)	(1,248)	
Exploration expense	(23,373)	(11,877)	(2,162)	(600)	(8,734)(a)
Dry hole and impairment expense	(26,945)	(26,136)		(809)	
Depreciation, depletion and amortization expense	(203,676)	(140,304)	(61,243)	(2,129)	
Pretax operating results	223,926	150,281	82,607	(228)	(8,734)
Income tax (expense) benefit	(96,590)	(52,598)	(46,322)	100	2,230
Operating results	$ 127,336	$ 97,683	$ 36,285	$ (128)	$ (6,504)
			2000		

Revenues	$	479,202	$	291,266	$	183,060	$	4,876	$	
Lease operating expense		(93,368)		(58,916)		(33,568)		(884)		
Exploration expense		(15,291)		(6,532)		(3,507)		(856)		(4,396)(b)
Dry hole and impairment expense		(28,608)		(28,142)				(466)		
Depreciation, depletion and amortization expense		(129,476)		(76,516)		(50,968)		(1,992)		
Pretax operating results		212,459		121,160		95,017		678		(4,396)
Income tax (expense) benefit		(87,307)		(41,059)		(47,509)		(278)		1,539
Operating results	$	125,152	$	80,101	$	47,508	$	400	$	(2,857)

(a) Included in Other are costs associated with activities related almost entirely to Hungary.

(b) Included in Other are costs associated with initial activities related to Hungary of $3,396, the British sector of the North Sea of $836, and the Danish sector of the North Sea of $164.

The following table sets forth the Company s costs incurred (expressed in thousands) for oil and gas producing activities during the years indicated.

	Total Company	United States	Kingdom of Thailand	Canada	Other
Costs incurred (capitalized unless otherwise indicated):					
2002:					
Property acquisition					
Unproved	$ 8,030	$ 8,030	$	$	$
Exploration					
Capitalized	43,165	40,028	3,137		
Expensed	4,783	2,797	1,907		79(a)
Development	303,197	205,035	98,162		
Interest	24,033	12,892	11,141		
Total oil and gas costs incurred	$ 383,208	$ 268,782	$ 114,347	$	$ 79
Provision for depreciation, depletion and amortization	$ 283,865	$ 218,636	$ 65,229	$	$
2001:					
Property acquisition					
Proved	$ 949,704	$ 949,673	$	$ 31	$
Unproved	172,947	172,947			
Exploration					
Capitalized	59,390	48,290	9,180	1,920	
Expensed	23,373	11,877	2,162	600	8,734(a)
Development	314,736	255,800	57,816	1,120	
Interest	33,242	27,046	6,196		
Total oil and gas costs incurred	$ 1,553,392	$ 1,465,633	$ 75,354	$ 3,671	$ 8,734
Provision for depreciation, depletion and amortization	$ 203,676	$ 140,304	$ 61,243	$ 2,129	$
2000:					
Property acquisition					
Proved	$ 8,393	$ 8,393	$	$	$
Unproved	10,725	7,602	1,394	1,729	
Exploration					
Capitalized	37,076	23,978	8,006	5,092	
Expensed	15,291	6,532	3,507	856	4,396(b)
Development	108,991	71,621	36,034	1,336	
Interest	20,918	5,446	15,472	-	
Total oil and gas costs incurred	$ 201,394	$ 123,572	$ 64,413	$ 9,013	$ 4,396
Provision for depreciation, depletion and amortization	$ 129,476	$ 76,516	$ 50,968	$ 1,992	$

(a) Included in Other are costs associated with activities related almost entirely to Hungary.

(b) Included in the expensed exploration costs reflected in Other are costs associated with initial activities related to Hungary of $3,396, the British sector of the North Sea of $836, and the Danish sector of the North Sea.

The following information regarding estimates of the Company s proved oil and gas reserves, which are located offshore in United States waters of the Gulf of Mexico, onshore in the United States and offshore in the Kingdom of Thailand is based on reports prepared by Ryder Scott Company, L.P. and Miller & Lents, Ltd. The definitions and assumptions that serve as the basis for the discussions under the caption Item 1, Business Exploration and Production Data Reserves should be referred to in connection with the following information.

Estimates of Proved Reserves

Oil, Condensate and Natural Gas Liquids (Bbls.)

	Total Company	United States	Kingdom of Thailand	Canada
Proved Reserves as of December 31, 1999	78,776,417	41,553,662	36,655,697	567,058
Revisions of previous estimates	2,335,209	2,561,793	(480,335)	253,751
Extensions, discoveries and other additions	24,741,720	19,115,830	5,546,923	78,967
Purchase of properties	23,657	23,657		
Sale of properties	(205,506)	(205,506)		
Estimated 2000 production	(10,350,000)	(5,571,000)	(4,657,000)	(122,000)
Proved Reserves as of December 31, 2000	95,321,497	57,478,436	37,065,285	777,776
Revisions of previous estimates	8,694,016	3,521,490	5,172,457	69
Extensions, discoveries and other additions	18,278,228	15,818,428	2,459,800	
Purchase of properties	10,115,300	10,115,300		
Sale of properties	(1,556,413)	(837,413)		(719,000)
Estimated 2001 production	(11,573,233)	(6,117,546)	(5,396,842)	(58,845)
Proved Reserves as of December 31, 2001	119,279,395	79,978,695	39,300,700	
Revisions of previous estimates	9,563,087	9,290,517	272,570	
Extensions, discoveries and other additions	8,460,885	3,965,585	4,495,300	
Sale of properties	(202,785)	(202,785)		
Estimated 2002 production	(18,921,750)	(12,939,750)	(5,982,000)	
Proved Reserves as of December 31, 2002	118,178,832	80,092,262	38,086,570	
Proved Developed Reserves as of:				
December 31, 1999	53,894,653	35,136,156	18,407,852	350,645
December 31, 2000	60,656,634	35,132,295	24,746,563	777,776
December 31, 2001	79,777,300	59,383,200	20,394,100	
December 31, 2002	97,873,000	74,041,149	23,831,851	

Estimates of Proved Reserves

Natural Gas (MMcf)

	Total Company	United States	Kingdom of Thailand	Canada
Proved Reserves as of December 31, 1999	374,698	220,129	153,588	981
Revisions of previous estimates	(2,245)	3,110	(5,518)	163
Extensions, discoveries and other additions	56,372	28,623	26,605	1,144
Purchase of properties	2,601	2,601		
Sale of properties	(1,195)	(1,195)		
Estimated 2000 production	(60,248)	(38,647)	(21,371)	(230)
Proved Reserves as of December 31, 2000	369,983	214,621	153,304	2,058
Revisions of previous estimates	11,749	(743)	12,492	
Extensions, discoveries and other additions	63,519	57,344	6,175	
Purchase of properties	468,776	468,776		
Sale of properties	(8,477)	(6,949)	-	(1,528)
Estimated 2001 production	(86,758)	(62,482)	(23,746)	(530)
Proved Reserves as of December 31, 2001	818,792	670,567	148,225	
Revisions of previous estimates	66,796	38,237	28,559	
Extensions, discoveries and other additions	89,774	78,575	11,199	
Estimated 2002 production	(101,852)	(73,473)	(28,379)	
Proved Reserves as of December 31, 2002	873,510	713,906	159,604	
Proved Developed Reserves as of:				
December 31, 1999	245,257	156,398	88,041	818
December 31, 2000	239,978	150,684	87,236	2,058
December 31, 2001	602,345	532,348	69,997	
December 31, 2002	687,556	600,255	87,301	

POGO PRODUCING COMPANY & SUBSIDIARIES

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS RELATED TO PROVED OIL AND GAS RESERVES Unaudited

The standardized measure of discounted future net cash flows from the production of proved reserves is developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods in which they are expected to be produced based on year-end economic conditions.

2. The estimated future gross revenues from proved reserves are priced on the basis of year-end market prices, except in those instances where fixed and determinable natural gas price escalations are covered by contracts.

3. The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year-end cost estimates, and the estimated effect of future income taxes. These cost estimates are subject to some uncertainty.

The standardized measure of discounted future net cash flows does not purport to present the fair value of the Company s oil and gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

The following are the principal sources of change in the standardized measure of discounted future net cash flows. All amounts are related to changes in reserves located in the United States, the Kingdom of Thailand, and Canada, as noted.

	Year Ended December 31, 2002		
	Total Company	**United States**	**Kingdom of Thailand**
		(Expressed in thousands)	
Beginning balance	$ 1,138,048	$ 826,570	$ 311,478
Revisions to prior years proved reserves:			
Net changes in prices and production costs	1,285,867	1,096,580	189,287
Net changes due to revisions in quantity estimates	255,617	202,952	52,665
Net changes in estimates of future development costs	(183,597)	(97,784)	(85,813)
Accretion of discount	240,283	189,055	51,228
Changes in production rate and other	(69,640)	(15,695)	(53,945)

Total revisions		1,528,530		1,375,108		153,422
New field discoveries and extensions, net of future production and development costs		334,335		218,991		115,344
Sales of properties		(2,344)		(2,344)		-
Sales of oil and gas produced, net of production costs		(607,486)		(433,049)		(174,437)
Previously estimated development costs incurred		304,661		206,499		98,162
Net change in income taxes		(640,529)		(476,987)		(163,542)
Net change in standardized measure of discounted future net cash flows		917,167		888,218		28,949
Ending balance	$	2,055,215	$	1,714,788	$	340,427

	Total Company		United States		Kingdom of Thailand		Canada
	Year Ended December 31, 2001						
	(Expressed in thousands)						
Beginning balance	$	1,715,176	$	1,327,734	$	370,630	$ 16,812
Revisions to prior years proved reserves:							
Net changes in prices and production costs		(1,184,494)		(1,083,561)		(100,933)	
Net changes due to revisions in quantity estimates		85,497		32,533		53,016	(52)
Net changes in estimates of future development costs		(149,719)		(120,496)		(28,784)	(439)
Accretion of discount		245,492		192,555		50,602	2,335
Changes in production rate and other		19,636		19,571		(4,666)	4,731
Total revisions		(983,588)		(959,398)		(30,765)	6,575
New field discoveries and extensions, net of future production and development costs		166,518		126,429		40,089	
Purchases of properties		345,728		345,728			
Sales of properties		(93,384)		(65,787)			(27,597)
Sales of oil and gas produced, net of production costs		(477,970)		(328,648)		(146,012)	(3,310)
Previously estimated development costs incurred		128,440		86,484		40,974	982
Net change in income taxes		337,128		294,028		36,562	6,538
Net change in standardized measure of discounted future net cash flows		(577,128)		(501,164)		(59,152)	(16,812)
Ending balance	$	1,138,048	$	826,570	$	311,478	$

	Total Company		United States		Kingdom of Thailand		Canada
	Year Ended December 31, 2000						
	(Expressed in thousands)						
Beginning balance	$	868,683	$	448,629	$	410,468	$ 9,586
Revisions to prior years proved reserves:							
Net changes in prices and production costs		817,201		839,536		(26,592)	4,257
Net changes due to revisions in quantity estimates		55,574		63,945		(13,759)	5,388
Net changes in estimates of future development costs		(22,657)		(43,119)		21,527	(1,065)
Accretion of discount		115,465		57,584		56,959	922
Changes in production rate and other		110,717		125,761		(13,029)	(2,015)
Total revisions		1,076,300		1,043,707		25,106	7,487
New field discoveries and extensions, net of future production and development costs		494,689		460,239		25,147	9,303
Purchases of properties		11,135		11,135			
Sales of properties		(5,712)		(5,712)			
Sales of oil and gas produced, net of production costs		(385,834)		(232,350)		(149,492)	(3,992)
Previously estimated development costs incurred		109,692		72,690		35,666	1,336
Net change in income taxes		(453,777)		(470,604)		23,735	(6,908)

Net change in standardized measure of discounted future net cash flows	846,493	879,105	(39,838)	7,226
Ending balance	$ 1,715,176	$ 1,327,734	$ 370,630	$ 16,812

	Total Company	United States	Kingdom of Thailand	Canada
	(Expressed in thousands)			
		2002		
Future gross revenues	$ 7,078,353	$ 5,486,454	$ 1,591,899	$
Future production costs:				
Lease operating expense	(1,819,485)	(1,150,305)	(669,180)	
Future development and abandonment costs	(406,101)	(267,578)	(138,523)	
Future net cash flows before income taxes	4,852,767	4,068,571	784,196	
Discount at 10% per annum	(1,754,411)	(1,573,013)	(181,398)	
Discounted future net cash flows before income taxes	3,098,356	2,495,558	602,798	
Future income taxes, net of discount at 10% per annum	(1,043,141)	(780,770)	(262,371)	
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$ 2,055,215	$ 1,714,788	$ 340,427	$
		2001		
Future gross revenues	$ 4,202,888	$ 3,115,416	$ 1,087,472	$
Future production costs:				
Lease operating expense	(1,354,815)	(899,262)	(455,553)	
Future development and abandonment costs	(445,239)	(325,600)	(119,639)	
Future net cash flows before income taxes	2,402,834	1,890,554	512,280	
Discount at 10% per annum	(862,174)	(760,201)	(101,973)	
Discounted future net cash flows before income taxes	1,540,660	1,130,353	410,307	
Future income taxes, net of discount at 10% per annum	(402,612)	(303,783)	(98,829)	
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$ 1,138,048	$ 826,570	$ 311,478	$
		2000		
Future gross revenues	$ 4,926,262	$ 3,624,205	$ 1,250,223	$ 51,834
Future production costs:				
Lease operating expense	(1,043,108)	(550,020)	(473,022)	(20,066)
Future development and abandonment costs	(316,467)	(196,308)	(119,476)	(683)
Future net cash flows before income taxes	3,566,687	2,877,877	657,725	31,085
Discount at 10% per annum	(1,111,771)	(952,332)	(151,704)	(7,735)
Discounted future net cash flows before income taxes	2,454,916	1,925,545	506,021	23,350
Future income taxes, net of discount at 10% per annum	(739,740)	(597,811)	(135,391)	(6,538)
Standardized measure of discounted future net cash flows related to proved oil and gas reserves	$ 1,715,176	$ 1,327,734	$ 370,630	$ 16,812

Quarterly Results Unaudited

Summaries of the Company s results of operations by quarter for the years 2002 and 2001 are as follows:

	Quarter Ended			
	Mar. 31	June 30	Sept. 30	Dec. 31
	(Expressed in thousands, except per share amounts)			
2002				
Revenues	$ 142,910	$ 184,385	$ 207,808	$ 216,338
Gross profit (a)	$ 40,821	$ 71,006	$ 86,040	$ 91,795
Net income	$ 9,025	$ 28,618	$ 31,637	$ 37,751
Earnings per share (b):				
Basic	$ 0.17	$ 0.51	$ 0.52	$ 0.62
Diluted	$ 0.17	$ 0.48	$ 0.51	$ 0.60
2001				
Revenues	$ 169,851	$ 170,384	$ 144,275	$ 125,607
Gross profit (a)	$ 85,232	$ 64,071	$ 45,938	$ 23,802
Net income	$ 39,946	$ 30,979	$ 15,603	$ 1,426
Earnings per share (b):				
Basic	$ 0.93	$ 0.58	$ 0.29	$ 0.03
Diluted	$ 0.80	$ 0.53	$ 0.28	$ 0.03

(a) Represents revenues less lease operating, natural gas purchases and other, exploration, dry hole, and impairment, and depreciation, depletion and amortization expenses.

(b) The sum of the individual quarterly earnings (loss) per share may not agree with year-to-date earnings (loss) per share as each quarterly computation is based on the income or loss for that quarter and the weighted average number of common shares outstanding during that period.

ITEM 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure.

Previously reported on Form 8-K, dated April 17, 2002.

PART III

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

The information responsive to Items 401 and 405 of Regulation S-K in the Company s definitive Proxy Statement for its annual meeting to be held on April 22, 2003, to be filed within 120 days of December 31, 2002 pursuant to Regulation 14A under the Securities Exchange Act of 1934, as amended (the Company s 2003 Proxy Statement), is incorporated herein by reference. See also Item S-K 401(b) appearing in Part I of this Form 10-K.

ITEM 11. ***Executive Compensation.***

The information responsive to Item 402 of Regulation S-K in the Company s 2003 Proxy Statement, other than the information regarding the Compensation Committee Report on Executive Compensation, is incorporated herein by

reference.

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

The information responsive to Item 403 of Regulation S-K in the Company s 2003 Proxy Statement is incorporated herein by reference.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information about the Common Stock that may be issued under all of the Company's existing equity compensation plans as of December 31, 2002:

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**Weighted average exercise price of outstanding options, warrants and rights**	**Number of securities remaining available for future issuance**
Equity compensation plans approved by security holders	2,553,642	$ 24.14	1,983,632(1)
Equity compensation plans not approved by security holders	1,179,804	$ 25.47	927,933(2)
Total	3,733,446	$ 24.54	2,911,565

(1) The securities remaining available for issuance under the approved plans may be issued in the form of stock options, stock appreciation rights, stock awards and performance shares. The shares remaining available for issuance may be used for any of these types of awards. The exercise price may be paid in cash or by tendering already-owned Common Stock. Awards are in general not transferrable, subject to exceptions in certain cases involving transfers to a family member or related entities if approved by the committee administering the plan.

(2) Shares remaining available for issuance under the 1998 Nonqualified Incentive Plan (the only non-approved plan) include only stock options and stock appreciation rights, the exercise or reference price of which may not exceed the fair market value of the Common Stock on the date of grant. The exercise price may be paid in cash or by tendering already-owned common stock. Awards are in general not transferrable, subject to exceptions in certain cases involving transfers to a family member or related entities if approved by the committee administering the plan.

ITEM 13. ***Certain Relationships and Related Transactions.***

The information responsive to Item 404 of Regulation S-K in the Company s 2003 Proxy Statement is incorporated herein by reference.

ITEM 14. ***Controls and Procedures.***

Within 90 days prior to the filing of this report, an evaluation was performed under the supervision and with the participation of the Company s management, including the Chairman, President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures. Based on that evaluation, the Company s management, including the Chairman, President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer, concluded that the Company s disclosure controls and procedures were effective in ensuring that material information relating to the Company with respect to the period covered by this report was made known to them. There have been no significant changes in the Company s internal controls or in other factors that could significantly affect internal controls subsequent to the date of that evaluation.

PART IV

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

(a) Financial Statements and Supplementary Data, Financial Statement Schedules and Exhibits

2. Financial Statement Schedules:

All Financial Statement Schedules have been omitted because they are not required, are not applicable or the information required has been included elsewhere herein.

3. Exhibits:

*2.1 Agreement and Plan of Merger dated as of November 19, 2000, among Pogo Producing Company, NORIC Corporation, and the shareholders signatory thereto (Exhibit 4.1, Current Report on Form 8-K filed March 26, 2001, File No. 1-7792).

*3.1 Restated Certificate of Incorporation of Pogo Producing Company (Exhibit 3(a), Annual Report on Form 10-K for the year ended December 31, 1997, File No. 1-7792).

*3.2 Amendment to Amended and Restated Certificate of Incorporation of Pogo Producing Company (Exhibit 4.3, Registration Statement on Form S-3, filed May 11, 2001, File No. 333-60800).

*3.3 Certificate of Designations of Series A Junior Participating Preferred Stock of Pogo Producing Company, dated April 26, 1994 (Exhibit 4(d), Registration Statement on Form S-8, filed August 9, 1994, File No. 33-54969).

*3.4 Bylaws of Pogo Producing Company, as amended and restated through July 16, 2002 (Exhibit 4.1, Quarterly Report on Form 10-Q for the quarter ended June 30, 2002, File No. 1-7792).

*4.1 Credit Agreement dated as of March 8, 2001 among Pogo Producing Company, as the Borrower, certain commercial lending institutions, as the Lenders, Bank of Montreal as Administrative Agent, Toronto Dominion (Texas), Inc., as Syndication Agent, BNP Paribas, as Documentation Agent and Bank of America, N.A. and Fleet National Bank, as Managing Agents (Exhibit 4.4, Current Report on Form 8-K filed March 26, 2001, File No. 1-7792).

*4.2 Indenture dated as of June 15, 1996, between Pogo Producing Company and Fleet National Bank (now State Street Bank & Trust Company as successor in interest under the Indenture), as Trustee (Exhibit 4(f), Quarterly Report on Form 10-Q for the quarter ended June 30, 1996, File No. 001-7792).

*4.3 Indenture dated as of May 15, 1997, between Pogo Producing Company and Fleet National Bank (now State Street Bank & Trust Company as successor in interest under the Indenture), as Trustee (Exhibit 4.3, Registration Statement on Form S-4, filed July 2, 1997, File No. 333-30613).

*4.4 Indenture dated as of January 15,1999, between Pogo Producing Company and State Street Bank & Trust Company as Trustee (Exhibit 4.2, Registration Statement on Form S-4, filed February 10, 1999, File No. 333-72129).

*4.5 Indenture dated as of April 10, 2001, between Pogo Producing Company and Wells Fargo Bank Minnesota, National Association, as Trustee (Exhibit 4.2, Registration Statement on Form S-4, filed April 24, 2001, File No. 333-59426).

*4.6 Rights Agreement dated as of April 26, 1994, between Pogo Producing Company and Harris Trust Company of New York, as Rights Agent (Exhibit 4, Current Report on Form 8-K filed, April 26, 1994, File No. 1-7792).

Other instruments defining the rights of holders of long-term debt of Pogo Producing Company and its subsidiaries are not being filed because the total amount of securities authorized by such instruments does not exceed 10% of the total assets of Pogo Producing Company and its subsidiaries on a consolidated basis as of December 31, 2002. Pogo Producing Company hereby agrees to furnish to the Commission a copy of any such debt instrument upon request.

Executive Compensation Plans and Arrangements (comprising Exhibits 10.1 through 10.18, inclusive)

*10.1 1989 Incentive and Nonqualified Stock Option Plan of Pogo Producing Company, as amended and restated effective January 25, 1994 (Exhibit 99, Definitive Proxy Statement on Schedule 14A, filed March 22, 1994, File No. 1-7792).

*10.2 Form of Stock Option Agreement under 1989 Incentive and Nonqualified Stock Option Plan, as amended and restated effective January 22, 1991 (Exhibit 10(d)(1), Annual Report on Form 10-K for the year ended December 31, 1991, File No. 0-5468).

*10.3 Form of Director Stock Option Agreement under 1989 Incentive and Nonqualified Stock Option Plan as amended and restated effective January 22, 1991 (Exhibit 10(d)(2), Annual Report on Form 10-K for the year ended December 31, 1991, File No. 0-5468).

*10.4	1995 Long-Term Incentive Plan (Exhibit 4(c), Registration Statement on Form S-8 filed May 22, 1996, File No. 333-04233).
*10.5	1998 Incentive Plan (Exhibit 4.7, Registration Statement on Form S-8 filed August 15, 2002, File No. 333-98205).
*10.6	2000 Incentive Plan (Exhibit B to the Company s Definitive Proxy Statement filed on Schedule 14A, March 27, 2000, File No. 001-7792).
*10.7	2002 Incentive Plan (Exhibit B to the Company s Definitive Proxy Statement filed on Schedule 14A, March 25, 2002, File No. 001-7792).
10.8	Executive Employment Agreement by and between Pogo Producing Company and Stuart P. Burbach, dated February 1, 2003.
10.9	Executive Employment Agreement by and between Pogo Producing Company and Jerry A. Cooper, dated February 1, 2003.
10.10	Executive Employment Agreement by and between Pogo Producing Company and R. Phillip Laney, dated February 1, 2003.
10.11	Executive Employment Agreement by and between Pogo Producing Company and John O. McCoy, Jr., dated February 1,2003.
10.12	Executive Employment Agreement by and between Pogo Producing Company and Paul G. Van Wagenen, dated February 1,2003.
10.13	Executive Employment Agreement by and between Pogo Producing Company and Bruce E. Archinal, dated as of February 1, 2003.
10.14	Executive Employment Agreement by and between Pogo Producing Company and David R. Beathard, dated as of February 1, 2003.
10.15	Executive Employment Agreement by and between Pogo Producing Company and Stephen R. Brunner, dated as of February 1, 2003.
10.16	Executive Employment Agreement by and between Pogo Producing Company and J. D. McGregor, dated as of February 1,2003.
10.17	Executive Employment Agreement by and between Pogo Producing Company and Gerald A. Morton, dated as of February 1, 2003.
10.18	Executive Employment Agreement by and between Pogo Producing Company and James P. Ulm, II, dated as of February 1, 2003.
*10.19	Amended and Restated Bareboat Charter Agreement by and between Tantawan Services, L.L.C. and Tantawan Production B.V., dated as of February 9,1996 (Exhibit 10.26, Annual Report on Form 10-K for the year ended December 31, 1999, File No. 001-7792).
*10.20	Bareboat Charter Agreement by and between Thaipo Limited, Thai Romo Limited, Palang Sophon Limited, B8/32 Partners Limited and Watertight Shipping B.V. dated as of August 24, 1998 (Exhibit 10.27, Annual Report on Form 10-K for the year ended December 31, 1999, File No. 001-7792).
*10.21	Gas Sales Agreement dated November 7, 1995, among The Petroleum Authority of Thailand, Thaipo, Limited, Thai Romo Ltd. and The Sophonpanich Co., Ltd. (Exhibit 10(k), Quarterly Report on Form 10-Q for the quarter ended June 30, 1996, File No. 001-7792).
*10.22	The First Amendment to the Gas Sales Agreement dated November 12, 1997, among The Petroleum Authority of Thailand, B8/32 Partners Limited, Thaipo, Limited, Thai Romo Limited and Palang Sophon Limited (Exhibit 10(g)(ii), Annual Report on Form 10-K for the year ended December 31, 1998, File No. 001-7792).
10.23	The Second Amendment to the Gas Sales Agreement dated effective as of October 1, 2001, among The Petroleum Authority of Thailand, Chevron Offshore (Thailand) Limited, Thaipo Limited, Palang Sophon Limited and B8/32 Partners Limited.
21	List of Subsidiaries of Pogo Producing Company
23.1	Consent of Arthur Anderson LLP (omitted pursuant to Rule 437a of the Securities Act).

23.2	Consent of PricewaterhouseCoopers LLP.
23.3	Consent of Ryder Scott Company, L.P.
23.4	Consent of Miller & Lents, Ltd.
24	Powers of Attorney from each director of Pogo Producing Company whose signature is affixed to this Form 10-K for year ended December 31, 2002.

* Asterisk indicates exhibits incorporated by reference as shown.

(b) Reports on Form 8-K

No reports on Form 8-K have been filed during the last quarter of the period covered by this report.

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.

POGO PRODUCING COMPANY
(REGISTRANT)

BY: /s/ PAUL G. VAN WAGENEN
Paul G. Van Wagenen
Chairman, President and Chief Executive Officer

Date: February 27, 2003

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 indicated on February 27, 2003.

Signatures	Title
/s/ PAUL G. VAN WAGENEN **Paul G. Van Wagenen** *Chairman, President and Chief Executive Officer*	Principal Executive Officer and Director
/s/ JAMES P. ULM, II **James P. Ulm, II** *Senior Vice President and Chief Financial Officer*	Principal Financial Officer
/s/ THOMAS E. HART **Thomas E. Hart** *Vice President and Chief Accounting Officer*	Principal Accounting Officer
/s/ JERRY M. ARMSTRONG **Jerry M. Armstrong**	Director
/s/ ROBERT H. CAMPBELL **Robert H. Campbell**	Director
/s/ WILLIAM L. FISHER **William L. Fisher**	Director
/s/ GERRIT W. GONG **Gerrit W. Gong**	Director

/s/ CARROLL W. SUGGS **Carroll W. Suggs**	Director
/s/ STEPHEN A. WELLS **Stephen A. Wells**	Director
/s/ THOMAS A. HART **Thomas E. Hart** *Attorney-in-Fact*	

CERTIFICATIONS

I, Paul G. Van Wagenen, certify that:

1. I have reviewed this annual report on Form 10-K of Pogo Producing Company (the Company);

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

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

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

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

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

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

5. The Company s other certifying officer and I have disclosed, based on our most recent evaluation, to the Company s auditors and the Audit Committee of the Company s Board of Directors:

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

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

6. The Company s other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 27, 2003

/s/ Paul G. Van Wagenen
Paul G. Van Wagenen
Chairman, President and Chief Executive Officer

CERTIFICATIONS

I, James P. Ulm, II, certify that:

7. I have reviewed this annual report on Form 10-K of Pogo Producing Company (the Company);

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

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

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

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

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

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

11. The Company s other certifying officer and I have disclosed, based on our most recent evaluation, to the Company s auditors and the Audit Committee of the Company s Board of Directors:

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

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

12. The Company s other certifying officer and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: February 27, 2003

/s/ James P. Ulm, II
James P. Ulm, II
Senior Vice President and Chief Financial Officer