POGO PRODUCING CO
Form 10-K
March 12, 2002

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

FORM 10-K

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

For the fiscal year ended December 31, 2001

¨ **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**
Pogo Trust I 6 1/2% Cumulative Quarterly Income Convertible Preferred Securities, Series A	**New York Stock Exchange**

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

5 1/2% 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 Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

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

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 $967,675,806 as of March 11, 2002 (based on $29.26 per share, the last sale price of the Common Stock as reported on the New York Stock Exchange Composite Tape on such date).

53,792,316 shares of the registrant s Common Stock were outstanding as of March 11, 2002.

DOCUMENT INCORPORATED BY REFERENCE

Portions of the Company s definitive Proxy Statement respecting the annual meeting of shareholders to be held on April 23, 2002 (to be filed not later than 120 days after December 31, 2001) 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, 2001 (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 statements 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, Oklahoma and Louisiana, and internationally, primarily in the Gulf of Thailand and in Hungary. As of December 31, 2001, the Company had interests in 78 lease blocks offshore Louisiana and Texas, approximately 434,122 gross acres onshore in the United States, approximately 714,053 gross acres offshore in the Kingdom of Thailand, approximately 193,631 gross acres in the Danish and U.K. sectors of the North Sea and approximately 781,771 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 four operating divisions and a New Ventures Group. The operating divisions are its Offshore Division, which is responsible for the Company s operations offshore Texas and Louisiana in the Gulf of Mexico; its Western Division, which is active in the Permian Basin area in New Mexico and West Texas and in the Madden Field in Wyoming; its Onshore Division, which includes the Company s onshore operations principally in South Texas and Louisiana; and the International Division, which has responsibility for the Company s operations on its Block B8/32 Concession in the Kingdom of Thailand (the Thailand Concession), as well as the Company s exploration licenses in the North Sea. The Company s New Ventures Group was responsible for the Company s exploration activities in Hungary during 2001.

Domestic Offshore Operations

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, 2001. During 2001, approximately 24% of the Company s natural gas production and 24% of the Company s oil and condensate production came from its domestic offshore properties, contributing approximately 28% of the Company s consolidated oil and gas revenues. The Company s exploration and development efforts are primarily focused in shallower waters of the Outer Continental Shelf where the Company held interests in 60 lease blocks on December 31, 2001. In recent years, the Company has selectively expanded its exploration efforts further offshore into deeper waters where the Company currently believes there are opportunities for discovering and profitably producing substantial quantities of oil and gas. As of December 31, 2001, the Company had interests in 18 lease blocks in water depths that range from 600 feet to approximately 4,900 feet.

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 2001 were approximately $170,800,000 (excluding approximately $87,700,000 of net property acquisitions principally related to the North Central acquisition), or 180% higher than the Company s domestic offshore capital and exploration expenditures of approximately $63,600,000 for 2000, and 213% higher than the Company s domestic offshore capital and exploration expenditures of approximately $56,900,000 (excluding approximately $1,500,000 of net property acquisitions) for 1999. The increase in the Company s domestic offshore capital and exploration expenditures for 2001, compared with 2000 and 1999, resulted primarily from increased expenditures for facilities construction and, to a lesser extent, increased development drilling. During 2001, the Company invested over $67,000,000 on facilities construction for its Gulf of Mexico operations, principally the fabrication and installation of a platform in the Company s Main Pass Blocks 61/62 Field and installation of subsea completions and platform tiebacks at the Company s Ewing Bank Block 871 Field and Mississippi Canyon Blocks 661/705 Field. The Company has currently budgeted approximately $129,000,000 for capital and exploration expenditures during 2002 in the Gulf of Mexico. A substantial portion of this budget, over $53,000,000, is related to fabrication and installation of two new platforms on the Company s Main Pass Blocks 61/62 Field, which are currently expected to be completed by the fourth quarter of 2002.

The Company maintains a significant presence in the Gulf of Mexico where it participated in drilling 27 wells during 2001, 89% of which were considered successful. At December 31, 2001, the Company held varying interests in 219 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 27 of the 78 offshore leases in which it had an interest on December 31, 2001.

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 2001, the Company completed the installation of a production platform and related facilities in its new wholly owned Main Pass Blocks 61/62 Field. In addition, the fabrication of an additional production platform and a pressure maintenance platform, together with related facilities, for this field were commenced during 2001. The Company currently estimates that the average cost of constructing and installing these three platforms will be approximately $29,000,000 per platform. Wells, platforms and related facilities are typically much more expensive in the deeper waters of the Gulf of Mexico. Occasionally, deep-water developments can be performed by means of subsea completion technology with the production then piped back to an existing platform. The Company participated in two subsea completion developments during 2001, at its Ewing Bank Block 871 Field and its Mississippi Canyon Blocks 661/705 Field, where the total facilities costs for both projects were approximately $45,000,000 ($31,000,000 net to the Company s working interest). The Company believes that future development projects in the deeper water areas of the Gulf of Mexico may require similar or greater capital commitments, each of which must be justified in the then current and anticipated future product price environment.

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 December 1970. As a result of such purchases and subsequent activities, as of December 31, 2001, the Company owned interests in 68 federal leases and 10 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 nine offshore leases through its acquisition of North Central. 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 fifteen leases in 2001. 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 drilling or improved production methods by the Company can provide attractive rates of return.

Domestic Onshore Operations

The Company s Onshore Division is headquartered in Houston, Texas, with field offices in Laredo and Manvel, Texas. The Company s Western Division 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, 2001, accounted for approximately 49% of the Company s total proved reserves, with the Onshore Division and the Western Division contributing approximately 20% and 29%, respectively, of the Company s total proved reserves. During 2001, approximately 49% of the Company s natural gas production and 29% of its oil and condensate production was from its domestic onshore properties, contributing approximately 41% of the Company s consolidated oil and gas revenues.

Exploration and Development

Western Division. The Company s Western Division has actively explored in the Permian Basin and West Texas areas for many years. Since the Company began exploring in the Brushy Canyon (Delaware) formation in October 1989, it has participated in drilling 480 wells in the Permian Basin and West Texas areas through December 31, 2001, including 29 wells in 2001, and participated in the discovery or development of over 25 oil and gas fields during that time. The Company believes that during the past nine years it has been one of the most active companies drilling for oil and natural gas in the southeastern New Mexico (Lea and Eddy Counties) portion of the Permian Basin where the Company has interests in over 131,000 gross acres. The Company currently plans to drill approximately 40 wells in the Permian Basin during 2002 in 15 known fields and exploratory prospects. Drilling objectives of these wells range in depth from 5,500 feet to 15,500 feet below the surface, and target numerous producing formations including, among others, the shallow Brushy Canyon (Delaware), Bone Springs and Strawn formations, to the deeper Morrow, Devonian and Ellenburger pay zones.

The Company s Western Division also actively participates in the exploration and development of the Madden Deep Unit in Central Wyoming, where the Company currently is credited with 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 clean 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. The Company owns a 12.4% working interest in this plant. Production from the Madison formation is currently limited to the gas plant s processing capacity of 132 MMcf per day. However, an expansion of the gas plant that is designed to increase its processing capacity to 312 MMcf per day is under construction, with the expansion scheduled to become fully operational in the fourth quarter of 2002. In addition, wells to the Madison formation are deep and technologically challenging to drill, taking up to 13 months to drill and complete. One well to the Madison formation, the Big Horn 7-34, is currently completing, while a second Madison formation well, the Big Horn 8-35, is currently drilling and is scheduled to reach its projected total depth in March of 2002. Another deep Madison well is currently budgeted to commence drilling in 2002 and an additional seven wells are budgeted to be drilled to the Lower Fort Union formation during the year.

Onshore Division. The Company s Onshore Division is actively exploring in Louisiana, East Texas and South Texas. During 2001, the Onshore Division participated in drilling 33 wells, 88% of which were successfully completed. In Southeast Louisiana, the Company drilled and completed four wells during 2001 on prospects that were identified through the Company s recently acquired Thibodaux 3-D seismic survey, which covers approximately 39,000 acres. A fifth well was completed in early 2002 and another well was recently spudded. The Company currently plans to drill a seventh well in this area in 2002.

In South Texas, the Company s Onshore Division 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 nine wells in the fourth quarter of 2001 utilizing four drilling rigs at various times during that period. The Company currently has three rigs working in the field and has budgeted to drill 20 wells there during 2002. In addition, the Company enjoys significant production from its Hundido Field, where it has an average approximately 98% working interest and its Hereford Ranch Field, where it has a 100% working interest. The Company currently has one rig actively drilling in the Hundido Field and currently plans to drill 5 wells there during 2002.

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 2001 were approximately $141,000,000 (excluding approximately $1,027,200,000 of net property acquisitions primarily related to the acquisition of North Central), or 156% 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, and 449% higher than the Company s onshore capital and exploration expenditures of approximately $25,700,000 (excluding approximately $25,100,000 of net property acquisitions) for 1999. The increase in the Company s onshore capital and exploration expenditures for 2001, compared to 2000 and 1999, resulted primarily from expenditures related to properties acquired in the North Central acquisition and, to a lesser extent, increased exploratory and development drilling in its other onshore core areas. The Company has currently budgeted approximately $126,000,000 for capital and exploration expenditures during 2002 in its domestic onshore areas.

Lease Acquisitions

As it has in recent years, in 2001 the Company also successfully participated in various onshore federal and state lease sales and acquired interests in prospective acreage from private individuals. As of December 31, 2001, the Company held interests in approximately 434,000 gross (236,000 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. Substantial portions of the Company s international operations are grouped under its wholly owned Dutch subsidiary, Pogo Overseas Production B.V. Currently, a wholly owned subsidiary of Pogo Overseas Production, Thaipo Limited (Thaipo) maintains an office in Bangkok, Thailand from which it oversees operations on the Thailand Concession. 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, 53.66% of the working interests in the Thailand Concession. Chevron 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 continues to exert substantial influence over the development of the Thailand Concession. As of December 31, 2001, the Company s proved reserves located in the Kingdom of Thailand accounted for approximately 25% of the Company s total proved reserves. During 2001, approximately 27% of the Company s natural gas production and 47% of its oil and condensate production came from its operations on the Thailand Concession, contributing approximately 31% of the Company s consolidated oil and gas revenues.

Exploration and Development

The Company s international capital and exploration expenditures were approximately $70,100,000 for 2001, or 46% higher than the Company s international capital and exploration expenditures of $53,400,000 for 2000, and 29% lower than the Company s international capital and exploration expenditures of approximately $111,500,000 for 1999. The increase in the Company s capital and exploration expenditures for 2001, compared to 2000, resulted primarily from expenditures for facilities costs, including construction and installation of the Maliwan A platform and fabrication of five platforms for installation in the Benchamas Field (Benchamas Field Phase II) and, to a lesser extent, from increased exploration expenditures in Hungary. The decrease in the Company s international capital and exploration expenditures for 2001, compared to 1999, resulted primarily from decreased expenditures due to completion of the Benchamas Field Phase I development which was substantially completed in 1999, that was not entirely offset by its Benchamas Field Phase II expenditures in the Kingdom of Thailand and increased exploration expenditures in Hungary. Substantially all of the Company s international capital expenditures for 2001 were related to the Company s license in the Kingdom of Thailand. However, during 2001, the Company incurred approximately $9,020,000 in exploration expenditures in Hungary, primarily related to 3-D seismic data acquisition in Hungary. The Company has currently budgeted approximately $85,000,000 for capital and exploration expenditures during 2002 in Thailand and other areas outside North America, including Hungary and the North Sea. Approximately $51,500,000 of these funds is budgeted for facilities upgrades and additions, including the construction and installation of five platforms in the Benchamas Field during 2002 as part of the Benchamas Field Phase II development program.

Thailand Concession

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 production in July 1999 from three production platforms, with natural gas and oil from these platforms 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 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 and condensate. Benchamas Field Phase I development was completed during the first quarter of 2000. There have been 72 wells drilled in the Benchamas Field, which currently has 52 producing wells (20 of which were horizontal wells) and 20 water injection wells. Benchamas Field Phase II development commenced in 2001. The jacket for the fourth platform in the field was set in late 2001. Currently construction of four more platforms is nearing completion, with installation of these platforms scheduled to commence in the first half of 2002.

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. Currently, there are approximately 45 wells producing from five platforms in the Tantawan Field. 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.

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 will be taken to the Benchamas Field production handling facilities for processing and sale.

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 license area during 2001. Another two wells are currently budgeted for 2002 in the Jarmjuree and surrounding areas. During 2001, Thaipo and its joint venture partners drilled seven wells on areas of the Thailand Concession that are not currently designated as production areas and have currently budgeted to drill additional exploration wells during 2002. Interpretation of the data provided by these wells and 3-D seismic data covering these areas 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 that they install so as to improve the overall economics of the project. The gross cost of the first five production platforms and related facilities in the Tantawan Field and the first three production platforms in the Benchamas Field averaged approximately $20,000,000 per platform. However, employing advanced platform facility design and advanced drilling and completion techniques, including slimhole, batch and horizontal drilling, the six new minimum facility platforms, including the Maliwan A platform and the five Benchamas Field Phase II platforms, are expected to cost closer to $10,000,000 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.

Other Areas of the World

North Sea. On December 1, 1998, Pogo North Sea Ltd., a British subsidiary of the Company, together with two joint venture partners, were successful in obtaining a license from the United Kingdom governing approximately 113,000 acres in the British sector of the North Sea. Terms of the license provided for a minimum work commitment that involved the acquisition, processing and interpretation of 3-D seismic data over the block. This work commitment has been satisfied. The initial exploratory term of this license expires on December 1, 2004, unless otherwise extended or a production license is granted. Pogo North Sea Ltd. and its joint venture partners have acquired 3-D seismic data over the license and the surrounding area and are currently evaluating it for potential drilling prospects.

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 a Danish subsidiary known as 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 have acquired and interpreted 2-D and new 3-D seismic surveys over the license. The Company and its joint venture partners intend to reprocess and reinterpret some existing seismic data during 2002.

Hungary. 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 will expire on April 19, 2005, with areas where commercial accumulation of hydrocarbons being held through the economic productive life of such reserves. During 2001, Pogo Hungary completed the acquisition of two 3-D seismic surveys. One 3-D survey covers approximately 97,000 acres, or 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. The Company s geologists and geophysicists are currently evaluating the extensive data acquired from these surveys and other government sources. Depending upon the results of these surveys and other factors, Pogo Hungary hopes to commence a multi-well drilling program beginning in 2003. In addition, the Company continues to evaluate other international opportunities that are consistent with the Company s international exploration strategy and expertise.

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, Thaipo and its joint venture partners were granted an extension of the exploratory term through July 31, 2001, and a similar extension has been granted through July 31, 2002. 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 until they believe that 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. See also Miscellaneous; Sales. 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, plus certain fixed dollar amounts payable at specified cumulative production levels. Revenue from production in Thailand is also subject to local income taxes and other similar governmental charges including a Special Remuneratory Benefit tax (SRB).

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 144 MMcf per day. In October 2001, Thaipo and its joint venture partners entered into a Memorandum of Understanding with PTT that, among other things, provides that PTT may take up to an additional approximately 58 billion cubic feet of gas through March 1, 2004 at production rates which vary, depending upon the time period, from 26 up to 85 Mcf per day (Supplemental DCQ) or 12MMcf to 40MMcf net to the Company. During 2001, gas sales to PTT averaged approximately 140 MMcf per day, with production in the fourth quarter averaging 158 MMcf per day after the effective date of the Memorandum of Understanding.

Thaipo and its joint venture partners are subject to certain penalties if they are unable to meet the DCQ under the Gas Sales Agreement or the Supplemental DCQ under the Memorandum of Understanding. 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. Under the Memorandum of Understanding, failure to meet the Supplemental DCQ will result in a credit against the next month s production under the Memorandum of Understanding of 12% of the then current sales price of the gas not delivered. Thaipo is currently meeting the minimum DCQ and 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.

The sales price under the Gas Sales Agreement is subject to automatic semi-annual adjustments based upon a formula which 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 under the Memorandum of Understanding is 88% of the then current sales price under the Gas Sales Agreement. As of December 31, 2001, the Company was receiving an average price of approximately $2.31 per Mcf under the Gas Sales Agreement and the Memorandum of Understanding. 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.

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 approximately 12.4% interest in the Lost Cabin Gas Plant located in the Madden Field, which currently has the capacity to process 132 MMcf of natural gas per day. This plant is operating at full capacity and is currently undergoing an expansion that is designed to increase its processing capacity to 312 MMcf per day by the fourth quarter of 2002. The Company owns approximately 19% of a cryogenic gas processing plant near Erath, Louisiana, which entitles it to process up to 186 MMcf of natural gas and 5,478 Bbls of natural gas liquids per day. This plant is not currently operating at full capacity. 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 the Erath gas plant and 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. During 2001, the Company successfully divested itself in several non-core assets, including a portion of its interest in the South Pass 49 pipeline and all of its interest in the Saginaw pipeline that runs from just outside Fort Worth, Texas to Wichita Falls, Texas.

Sales

The marketing of 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 may 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 offshore properties are generally located in areas where a pipeline infrastructure is well developed and there is adequate availability in such pipelines 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 we find and could produce 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 our Thailand Concession. All oil and condensate production from the Tantawan Field is initially stored aboard the FPSO and is 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 and such production is currently also sold on a tanker load by tanker load basis, similar to the way Tantawan Field crude 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 a high wax content. Therefore, it is highly 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 2001, the price that the Company received for its crude oil production from its Thailand Concession ranged between $0.05 and $1.80 per Bbl less than the Malaysian Tapis Blend benchmark price. The Company and its joint venture partners continue to examine ways to improve the price that it receives for its 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 off load the oil and condensate it has purchased. See International Operations; Contractual Terms Governing the Thailand Concession and Related Production.

The marketing of onshore oil and gas production is also subject to the availability of pipelines, crude oil hauling and other transportation, processing and refining facilities as well as the existence of adequate markets. Generally, the Company s onshore oil and gas production is located in areas where commercial production of economic discoveries can be rapidly effectuated.

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 which may exist from time to time, and which 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.

With the exception of PTT, in which the Thai government has an ownership interest that exceeds 70%, to whom all of the Company s gas production in Thailand is sold, and Enron Corp. and its affiliates, to whom total sales constituted approximately 24% of the Company consolidated domestic revenues, sales to no customer in 2001 constituted more than 10% of the Company s consolidated Thai or domestic revenues. As part of its standard business practices, the Company attempts to monitor the credit worthiness of the companies to whom it sells its oil and gas production. During the fourth quarter of 2001, the Company began reducing the quantity of its oil and gas production that it sold to Enron Corp. and its affiliates and, where possible, began demanding security for those sales that it did make. On December 2, 2001, Enron Corp. and certain of its affiliates declared bankruptcy. Prior to its bankruptcy, the Company requested financial assurances from an Enron affiliate to assure its 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. As of December 31, 2001, the Company had an accounts receivable, net of applicable reserve, of $1,538,000 due from the Enron affiliate for physical sales of natural gas in November 2001 by North Central under its natural gas sales agreement. As of March 1, 2002, neither the Company, nor any of its subsidiaries, were selling any of their production to Enron Corp. or any its affiliates, nor did the Company or any of its subsidiaries have any commodity hedges or other derivative trading exposure with them. The Company does not currently expect that the bankruptcy of Enron and certain of its subsidiaries will have a material adverse effect on the business and operations of the Company.

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, which 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 their 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 a 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 our cash flow and profitability. Sustained periods of low prices could cause us to shut in existing production and could also have a material adverse effect on the Company s 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 for the covered period, which increases could be significant. As of December 31, 2001, the Company was a party to the natural gas 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 their attempting 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 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, 2001:

	Developed Acreage(a)		Undeveloped Acreage(b)	
	Gross	Net	Gross	Net
Domestic Offshore				
Louisiana (State)	12,067	4,467	5,830	3,177
Louisiana (Federal)	128,442	38,690	115,204	54,069
Texas (Federal)	17,280	6,141	51,145	14,082
Total Domestic Offshore	157,789	49,298	172,179	71,328
Domestic Onshore				
Louisiana	11,629	3,142	14,951	6,771
New Mexico	43,264	30,874	87,779	62,465
Texas	107,173	46,863	99,681	76,137
Wyoming	28,924	3,657	34,521	4,194
Other	6,120	2,211	80	15
Total Domestic Onshore	197,110	86,747	237,012	149,582
Total Domestic	354,899	136,045	409,191	220,910
International				
Gulf of Thailand	385,035	178,431	329,018	152,471
North Sea			112,729	45,092
Hungary			781,771	781,771
Denmark			80,902	32,361
Total International	385,035	178,431	1,304,420	1,011,695
Total Company	739,934	314,476	1,713,611	1,232,605

(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 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 the Benchamas Field, the Tantawan Field, the Maliwan Field and the North Jarmjuree production area.

(b) Approximately 44% of the Company s total domestic offshore net undeveloped acreage and approximately 15% of the Company s total domestic onshore net undeveloped acreage are under leases that have terms expiring in 2002 (unless otherwise extended). Approximately 4% of total domestic offshore net undeveloped acreage and approximately 17% of total domestic onshore net undeveloped acreage are under leases with terms expiring in 2003 (unless otherwise extended). All of the Company s undeveloped acreage in the Kingdom of Thailand is subject to one-year lease extensions which 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 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

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.

	2001	2000	1999
Average Production (lifting) Costs per Mcfe(a):			
Located in the United States	$ .81	$ .82	$ .69
Located in the Kingdom of Thailand	$ .65	$ .69	$ .99
Total Company	$ .75	$ .77	$ .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, $.88 in 2000 and $1.10 in 1999.

Productive Wells and Drilling Activity

The following table shows the Company s interest in productive oil and natural gas wells as of December 31, 2001. 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)		Natural Gas Wells(a)	
	Gross	**Net**	**Gross**	**Net**
Domestic Offshore	166	42.3	53	15.9
Domestic Onshore	694	514.5	522	239.1
Kingdom of Thailand	49	22.7	52	24.1
Total	909	579.5	627	279.1

(a) One or more completions in the same bore hole are counted as one well. The data in the above table includes 6 gross (1.5 net) oil wells and 22 gross (6.5 net) natural gas wells with multiple completions.

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.

	2001		2000		1999	
	Productive	**Dry**	**Productive**	**Dry**	**Productive**	**Dry**
Gross Wells:						
Offshore United States						
Exploratory	2.0	3.0	4.0	5.0	4.0	
Development	22.0		23.0	3.0	11.0	
Onshore United States and Canada(a)						
Exploratory	7.0	3.0	14.0	5.0	3.0	3.0
Development	61.0	3.0	39.0		23.0	1.0
Offshore Kingdom of Thailand						
Exploratory	11.0		7.0	3.0	4.0	
Development	18.0		24.0		42.0	
Total	121.0	9.0	111.0	16.0	87.0	4.0
Net Wells:						
Offshore United States						
Exploratory	2.00	1.73	2.16	2.37	1.32	
Development	8.34		6.19	1.00	3.37	
Onshore United States and Canada(a)						
Exploratory	4.97	1.33	3.81	2.46	1.63	1.65
Development	37.96	1.65	28.09		13.89	.80
Offshore Kingdom of Thailand						
Exploratory	5.10		3.24	1.39	1.85	
Development	8.34		11.12		19.46	
Total	66.71	4.71	54.61	7.22	41.52	2.45

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

Reserves

The following table sets forth information as to the Company s net proved and proved developed reserves as of December 31, 2001, 2000 and 1999, 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,		
	2001	**2000**	**1999**
Total Proved Reserves:			
Oil, condensate, and natural gas liquids (MBbls)			
Located in the United States and Canada(a)	79,979	58,257	42,120
Located in the Kingdom of Thailand	39,301	37,065	36,656
Total Company	119,280	95,322	78,776
Natural Gas (MMcf)			
Located in the United States and Canada(a)	670,567	216,679	221,110
Located in the Kingdom of Thailand	148,225	153,304	153,588
Total Company	818,792	369,983	374,698
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in the United States and Canada(a)	$ 1,130,353	$ 1,948,895	$ 585,052
Located in the Kingdom of Thailand	410,307	506,021	569,594
Total Company	$ 1,540,660	$ 2,454,916	$ 1,154,646
Total Proved Developed Reserves:			
Oil, condensate, and natural gas liquids (MBbls)			
Located in the United States and Canada(a)	59,383	35,910	35,487
Located in the Kingdom of Thailand	20,394	24,747	18,408
Total Company	79,777	60,657	53,895
Natural Gas (MMcf)			
Located in the United States and Canada(a)	532,348	152,742	157,216
Located in the Kingdom of Thailand	69,997	87,236	88,041
Total Company	602,345	239,978	245,257
Present value of estimated future net revenues, before income taxes (in thousands)			
Located in the United States and Canada(a)	$ 951,040	$ 1,246,068	$ 472,856
Located in the Kingdom of Thailand	241,860	445,033	304,275

Total Company	$ 1,192,900	$ 1,691,101	$ 777,131

(a) The Company sold its operations and reserves in Canada effective August 31, 2001 as part of an asset rationalization process. Consequently, year-end 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 present 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 Thai 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 Thai reserves are of limited value for comparative purposes.

Natural gas liquids comprised approximately 6% of the Company s total proved liquids reserves and approximately 9% of the Company s proved developed liquids reserves as of December 31, 2001. 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,		
	2001	**2000**	**1999**
Initial Weighted Average Price (in dollars):			
Oil, condensate, and natural gas liquids (per Bbl)			
Located in the United States and Canada	$ 18.75	$ 26.10	$ 25.55
Located in the Kingdom of Thailand	$ 18.94	$ 24.23	$ 25.08
Natural Gas (per Mcf)			
Located in the United States and Canada	$ 2.48	$ 10.14	$ 2.14
Located in the Kingdom of Thailand	$ 2.31	$ 2.27	$ 1.99

In computing future revenues from gas reserves attributable to the Company s domestic interests, prices in effect at December 31, 2001 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 somewhat lower 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, 2001 were used and these prices were held constant to depletion of the properties. The future 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 and the price provided for in the Memorandum of Understanding for excess sales volumes 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, 2001, 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 which 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, 2001, and this price was held constant until depletion of the Company s reserves in the Kingdom of Thailand. The future 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. For properties located onshore, the estimates of future net revenues and the present value thereof do not consider the salvage value of the lease equipment or the abandonment cost of the lease since both are relatively insignificant and tend to offset each other. The estimated net cost of abandonment after salvage was considered for offshore properties where such costs net of salvage are significant. 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 2001. 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 revisions 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 2001, 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.

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. 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 2001, the Company incurred capital expenditures of approximately $1,432,000 for environmental control facilities, primarily relating to the cost of installing environmental equipment on the Company s Main Pass Blocks 61/62 Field A platform, 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 $1,180,000 for expenditures involving environmental control facilities during 2002, including, among other things, the conversion of one well to a salt water disposal well, 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 Minerals Management Service of the Department of the Interior (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. The MMS is currently engaged in developing new oil and gas valuation regulations for royalty purposes. The gas rule was published in final form on December 16, 1997. Industry trade associations challenged portions of the rule and, on March 28, 2000, a district court invalidated the challenged regulations. The MMS has appealed the court s decision, and the appeal remains pending. The oil rule was published in final form on March 15, 2000. Industry trade associations have also challenged portions of this rule in court and the case remains pending. We are not in a position to predict the outcome of the litigation, but the Company believes that the impact of the final rules that emerge from the court review will 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, 2001, the Company and its subsidiaries had 220 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.

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.***

Executive officers of the Company are appointed annually to serve for the ensuing year or until their successors have been elected or appointed. The executive officers of the Company, their age as of December 31, 2001, and the year each was elected to his present position are as follows:

Executive Officer	Executive Office	Age	Year Elected
Paul G. Van Wagenen	Chairman of the Board, President and Chief Executive Officer	55	1991
Stuart P. Burbach	Executive Vice President Exploration	49	1998
Jerry A. Cooper	Senior Vice President and Western Division Manager	53	1998
R. Phillip Laney	Senior Vice President and Manager of Worldwide New Ventures	61	1998
John O. McCoy, Jr.	Senior Vice President and Chief Administrative Officer	50	1998
J. D. McGregor	Senior Vice President Sales	57	1998
Barry W. Acomb	Vice President and Offshore Division Manager	49	1999
Bruce E. Archinal	Vice President and Onshore Division Manager	49	1997
David R. Beathard	Vice President Engineering	43	1997
Stephen R. Brunner	Vice President Operations	43	1997
Frank Davis III	Vice President Land	55	1997
Thomas E. Hart	Vice President and Chief Accounting Officer	58	1999
Michael J. Killelea	Vice President and General Counsel	39	2001
Gerald A. Morton	Vice President Law, Chief Regulatory Officer and Corporate Secretary	43	2001
S. Clay Robinson, Jr.	Vice President and International Division Manager	47	1999
James P. Ulm, II	Vice President and Chief Financial Officer	38	1999

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 officer for more than the last five years was as follows: 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 Vice President and Western Division Manager for the Company since 1990; Mr. Laney, who joined the Company in 1977, served as Vice President and International Exploration Manager for the Company since 1991; Mr. McCoy, who joined the Company in 1978, served as Vice President and Chief Administrative Officer of the Company since 1989; Mr. McGregor, who joined the Company in 1981, served as Vice President-Sales since 1988; Mr. Acomb served as Offshore Division Exploration Manager since joining the Company in 1994; Mr. Archinal, who joined the Company in 1982, served as the Company s Onshore Division Manager since 1994; Mr. Beathard, who joined the Company in 1982, served as Manager of Petroleum Engineering for the Company since 1991; Mr. Brunner, who joined the Company in 1994, served as Resident Manager of the Company s Thailand operations since 1995; Mr. Davis, who joined the Company in 1978, served as Land Manager for the Company since 1991; Mr. Hart was Vice President and Controller since 1988 and prior thereto was Controller since joining the Company in 1977; 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; Mr. Morton, who joined the Company in 1993, was Vice President Law and Corporate Secretary since 1997; Mr. Robinson served as International Division Exploration Manager since joining the Company in 1996; and 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.

PART II

ITEM 5. ***Market for the Registrant s Common Stock and Related Security 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
2000		
1st Quarter	$ 18.38	$ 28.75
2nd Quarter	$ 21.13	$ 29.75
3rd Quarter	$ 18.00	$ 29.44
4th Quarter	$ 22.50	$ 33.19
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

As of March 1, 2002, there were 2,471 holders of record of the Company s Common Stock.

In each of 2000 and 2001, the Company paid four quarterly dividends of $0.03 per share on its Common Stock. However, the declaration and payment of future 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 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. In addition, the 6 1/2% Cumulative Quarterly Income Convertible Preferred Securities, Series A (the Trust Preferred Securities) issued by the Company s subsidiary, Pogo Trust I, prohibit the Company from paying dividends on the Company s Common Stock if dividends have not been paid on the Trust Preferred Securities.

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

	For the Year Ended December 31,				
	2001(a)	2000	1999	1998	1997
	(Expressed in thousands, except per share and production data)				
Financial Data					
Revenues:					
Crude oil and condensate	$ 261,226	$ 272,932	$ 109,803	$ 74,703	$ 112,603
Natural gas	322,390	190,401	111,152	116,148	158,500
Natural gas liquids	12,461	15,869	9,544	9,303	13,748
Oil and gas revenues	596,077	479,202	230,499	200,154	284,851
Pipeline sales and other	8,423	15,113	7,159	2,741	349
Gains (losses) on sales	1,000	3,676	37,458	(92)	1,100
Total	$ 605,500	$ 497,991	$ 275,116	$ 202,803	$ 286,300
Income (loss) before cumulative effect of change in accounting principle	$ 87,954	$ 89,023	$ 22,134	$ (43,098)	$ 37,116
Cumulative effect of change in accounting principle		(1,768)			
Net income (loss)	$ 87,954	$ 87,255	$ 22,134	$ (43,098)	$ 37,116
Per share data:					
Income (loss) before cumulative effect of change in accounting principle					
Basic	$ 1.72	$ 2.20	$ 0.55	$ (1.14)	$ 1.11
Diluted	$ 1.62	$ 1.99	$ 0.55	$ (1.14)	$ 1.06
Cash dividends on Common Stock	$ 0.12	$ 0.12	$ 0.12	$ 0.12	$ 0.12
Price range of Common Stock:					
High	$ 34.50	$ 33.19	$ 23.44	$ 34.69	$ 49.88
Low	$ 20.45	$ 18.00	$ 8.94	$ 9.81	$ 27.00
Weighted average number of common shares outstanding	51,031	40,445	40,178	37,902	33,421
Long-term debt	$ 794,990	$ 365,000	$ 375,000	$ 434,947	$ 348,179
Trust Preferred Securities, net	$ 145,086	$ 144,913	$ 144,751		
Shareholders equity	$ 824,885	$ 358,271	$ 268,512	$ 249,660	$ 146,106
Total assets	$ 2,426,408	$ 1,114,649	$ 948,193	$ 862,396	$ 676,617
Production (Sales) Data					
Net daily average production and weighted average price:					
Natural gas (Mcf per day)	237,800	164,600	141,600	159,000	181,700
Price (per Mcf)	$ 3.71	$ 3.16	$ 2.15	$ 2.00	$ 2.39
Crude oil-condensate (Bbl per day)	29,836	25,788	16,036	15,775	15,927
Price (per Bbl)	$ 23.99	$ 28.92	$ 18.76	$ 12.97	$ 19.37
Natural gas liquids (Bbl per day)	2,118	2,141	2,077	2,422	2,923
Price (per Bbl)	$ 16.12	$ 20.25	$ 12.59	$ 10.52	$ 12.89
Capital Expenditures (including interest capitalized)					
Oil and gas:					
Domestic Offshore					
Exploration	$ 18,000	$ 18,700	$ 12,600	$ 20,200	$ 18,700
Development	169,000	43,700	43,200	42,500	59,800
Purchase of reserves	87,700			5,000	900
Onshore North America					
Exploration	38,300	19,700	9,800	16,500	18,100
Development	113,600	34,700	19,800	28,100	38,400
Purchase of reserves	1,027,200	8,400	19,500	133,100	1,700
International					
Exploration	11,500	9,400	3,500	11,600	21,700
Development	64,700	51,500	106,300	95,500	62,500
Purchase of reserves					29,300
Total oil and gas	1,530,000	186,100	214,700	352,500	251,100
Other	4,800	700	2,200	6,300	4,000

Total	$ 1,534,800	$ 186,800	$ 216,900	$ 358,800	$ 255,100

(a) The financial, production and other data for 2001 reflect, among other things, the Company s acquisition of North Central from and after March 14, 2001.

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 the 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 Company acquired North Central through a direct merger with its parent company, NORIC Corporation. The Company accounted for the merger using the purchase method of accounting. Therefore, the information contained in this Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this Annual Report do 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.

As part of an ongoing asset rationalization process, the Company identified certain non-core properties and assets that it felt were underperforming, had little or no remaining upside potential, or faced significant future expenditures that would result in an unacceptable rate of return. Certain of these assets were sold during 2001, including the Company s Canadian operations, which were sold effective August 31, 2001, its Saginaw pipeline and certain of its other non-core oil and gas properties that were divested during the fourth quarter.

Results of Operations

Net Income

The Company reported 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), compared to 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), and net income for 1999 of $22,134,000 or $0.55 per share (on both a basic and a diluted basis). Net income in 2000 was adversely affected by a one-time $1,768,000 non-cash charge related to a change in accounting principles required by the Commission. Historically, the Company recorded oil and condensate inventory held for sale (principally in the FPSO and FSO in Thailand) at fair market value as of the close of the accounting period. However, the Commission announced in 2000 that it would require such inventory to be recorded as inventory at cost. The $1,768,000 one-time charge reflects a catch up adjustment for years prior to 2000. The Company does not currently expect to incur any similar charges related to this issue in the future. Among other items affecting net income for 2001, 2000 and 1999 were net gains of $1,000,000, $3,676,000 and $37,458,000, respectively, related to the Company s sale of certain non-strategic properties as part of its asset rationalization process. The $1,000,000 recorded in 2001 reflects gains of $5,983,000 on the sale of the Company s Canadian operations, a partial interest in the Company s South Pass 49 pipeline and various non-strategic offshore properties, which was partially offset by a $4,983,000 loss on the sale of the Company s Saginaw pipeline and various other non-strategic offshore properties. The Company has announced that it will continue to examine its underperforming and 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 2001 of 51,031,000 (60,822,000 on a diluted basis), compared to 40,445,000 (50,155,000 on a diluted basis) for 2000 and 40,178,000 (40,390,000 on a diluted basis) for 1999. The increase in the weighted average number of common shares outstanding for 2001, compared to 2000 and 1999, resulted primarily from the issuance of 12,615,816 shares of common stock to former shareholders of NORIC on March 14, 2001, in connection with the North Central acquisition 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 computation on a diluted basis in 2000 and 2001 primarily reflects 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 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. The earnings per share computation on a diluted basis in 1999 reflect 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 2001 were $605,500,000, an increase of approximately 22% compared to total revenues of $497,991,000 for 2000, and an increase of approximately 120% compared to total revenues of $275,116,000 for 1999. The increase in the Company s total revenues for 2001, compared to 2000 and 1999, resulted primarily from increased oil and gas revenues that were partially offset, in comparison with 1999, by a decrease in gains on property sales.

Oil and Gas Revenues

The Company s oil and gas revenues for 2001 were $596,077,000, an increase of approximately 24% from oil and gas revenues of $479,202,000 for 2000, and an increase of approximately 159% from oil and gas revenues of $230,499,000 for 1999. The following table reflects an analysis of variances in the Company s oil and gas revenues (expressed in thousands) between 2001 and the previous two years:

	2001 Compared to	
	2000	**1999**
Increase (decrease) in oil and gas revenues resulting from variances in:		
Natural gas		
Price	$ 33,378	$ 80,781
Production	98,611	130,457
	$ 131,989	$ 211,238
Crude oil and condensate		
Price	$ (46,521)	$ 30,607
Production	34,815	120,816
	$ (11,706)	$ 151,423
Natural Gas Liquids	$ (3,408)	$ 2,917
Increase (decrease) in oil and gas revenues	$ 116,875	$ 365,578

The increase in the Company s oil and gas revenues in 2001, compared to 2000, is related to increases in the Company s hydrocarbon production volumes and, to a lesser extent, increases in the average prices that it received for its natural gas production volumes, which was only partially offset by decreases in the average prices that the Company received for its crude oil and condensate production volumes. The increase in the Company s oil and gas revenues in 2001, compared to 1999, is related to increases in the Company s hydrocarbon production volumes and, to a lesser extent, increases in the average prices that the Company received for such production volumes. The increase in oil and gas revenues for 2001, compared to 2000, was also partially offset by a decline in the average price that the Company received for its NGL production volumes from $20.25 in 2000 to $16.12 in 2001.

	2001	2000	% Change 2001 to 2000	1999	% Change 2001 to 1999
Comparison of Increases (Decreases) in:					
Natural Gas					
Average prices:					
North America	$ 4.25	$ 3.69	15	$ 2.31	84
Kingdom of Thailand (Thai Baht)(a)	102	79	29	61	67
Company-wide average price	$ 3.71	$ 3.16	17	$ 2.15	73
Average daily production volumes (MMcf per day):					
North America	172.8	106.2	63	102.6	68
Kingdom of Thailand(a)	65.1	58.4	11	39.0	67
Company-wide average daily production	237.9	164.6	45	141.6	68
Crude Oil and Condensate					
Average prices:					
North America	$ 24.60	$ 27.83	(12)	$ 17.43	41
Kingdom of Thailand	$ 23.38	$ 30.10	(22)	$ 23.49	0
Company-wide average price	$ 23.99	$ 28.92	(17)	$ 18.76	28
Average daily production volumes (Bbls per day):					
North America	14,804	13,432	10	12,517	18
Kingdom of Thailand(a)	15,032	12,356	22	3,519	327
Company-wide average daily production	29,836	25,788	16	16,036	86
Total Liquid Hydrocarbons					
Company-wide average daily production (Bbls per day)	31,954	27,929	14	18,112	76

(a) Production from the Benchamas Field commenced in July 1999. The contractual provisions of the Gas Sales Agreement negatively affected prices received for the Company s natural gas production during the period from October 1998 through August 1999 when the Company did not meet the contractual DCQ.

Natural Gas

Thailand Prices. The price that the Company receives under the Gas Sales Agreement for its natural gas production from the Thailand Concession normally adjusts on a semi-annual basis. 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. During 2001, these indices and factors, including the Thai Baht dollar exchange rate, were relatively stable; resulting in no adjustments to the gas price other than the two regularly scheduled semi-annual adjustments. Prices received by the Company under the recently signed Memorandum of Understanding are 88% of the then current price under the Gas Sales Agreement. In addition, certain penalty provisions in the Gas Sales Agreement adversely affected prices received by the Company for its natural gas production during the period from October 1, 1998 through August 1999. See Business International Operations; Contractual Terms Governing the Thailand Concession and Related Production.

Production. The increase in the Company s natural gas production during 2001, compared to 2000 and 1999, was primarily related to the production from properties acquired in the North Central acquisition and, to a lesser extent, increased production from the Company s Thailand Concession, which was partially offset by decreased production from the Company s properties located in the Gulf of Mexico due to natural production decline. The Company currently believes that production from its Mississippi Canyon Blocks 601/705 Field and other development drilling projects scheduled for 2002 will lead to increased natural gas production from the Gulf of Mexico in 2002.

Crude Oil and Condensate

Thailand Prices. Since the inception of production from the Tantawan Field, crude oil and condensate has been stored on the FPSO until an economic quantity was 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. 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 Blend crude and are denominated in dollars. The differential has varied over the years and is influenced by a number of factors including, among others, tanker availability, worldwide crude oil supply and demand, the size of the lifting and the perceived quality of the production from the Tantawan and Benchamas Fields. Over the last year, the differential has generally ranged anywhere from $0.05 to $1.80 per Bbl below the Malaysian Tapis Blend benchmark price. In addition, the Company has generally been paid for its crude oil and condensate production from Thailand in dollars. As discussed previously under Results of Operations; Net Income, 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 price is recorded as income.

Production. The increase in the Company s crude oil and condensate production during 2001, compared to 2000 and 1999, resulted primarily from increased production from the Benchamas Field in the Kingdom of Thailand and, to a lesser extent, production from properties obtained in the North Central acquisition, which was partially offset by a decline in production from certain of the Company s other domestic properties, principally in the offshore Gulf of Mexico. The Company currently expects that its crude oil and condensate production will increase substantially in 2002, primarily as a result of increased production from the Company s Main Pass Blocks 61/62 Field, which commenced production in early January 2002, its Ewing Bank Block 871 Field which commenced production in the first quarter of 2002 and the Benchamas Field where facility capacity upgrades and five new platforms are scheduled for completion during 2002.

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 decrease in NGL revenues for 2001, compared with 2000, primarily related to a substantial decrease in the average price that the Company received for its NGL production, from $20.25 per Bbl in 2000 to $16.12 per Bbl in 2001, and a small decrease in NGL production. The increase in NGL revenues for 2001, compared to 1999, primarily related to an increase in the average price that the Company received for its NGL production, from $12.59 per Bbl in 1999 to $16.12 per Bbl in 2001 and a small increase in NGL production.

Costs and Expenses

	2001	2000	% Change 2001 to 2000	1999	% Change 2001 to 1999
Comparison of Increases (Decreases) in:					
Lease Operating Expenses					
North America	$ 81,164,000	$ 60,072,000	35	$ 48,121,000	69
Kingdom of Thailand	36,993,000	33,568,000	10	22,228,000	66
Total Lease Operating Expenses	$ 118,157,000	$ 93,640,000	26	$ 70,349,000	68
Pipeline Operating and Natural Gas Purchases	$ 11,373,000	$ 15,090,000	(25)	$ 6,481,000	75
General and Administrative Expenses	$ 39,162,000	$ 34,568,000	13	$ 29,452,000	33
Exploration Expenses	$ 23,373,000	$ 15,291,000	53	$ 5,982,000	291
Dry Hole and Impairment Expenses	$ 26,945,000	$ 28,608,000	(6)	$ 4,594,000	487
Depreciation, Depletion and Amortization Expenses	$ 206,609,000	$ 131,151,000	58	$ 104,266,000	98
DD&A rate	$ 1.32	$ 1.07	23	$ 1.12	18
Mcfe sold	156,780,000	121,581,000	29	91,351,000	72
Interest					
Charges	$ (56,259,000)	$ (34,064,000)	65	$ (35,874,000)	57
Income	$ 3,226,000	$ 2,634,000	22	$ 1,208,000	167
Capitalized Interest Expense	$ 33,242,000	$ 20,918,000	59	$ 17,733,000	87
Minority Interest Dividends and costs associated with preferred securities of a subsidiary trust	$ (9,999,000)	$ (9,965,000)	0	$ (5,914,000)	69
Foreign Currency Transaction Gains (Loss)	$ (524,000)	$ (3,174,000)	(84)	$ 572,000	N/A
Income Tax Expense	$ (61,613,000)	$ (66,969,000)	(8)	$ (9,583,000)	543

Lease Operating Expenses

The increase in North American lease operating expenses for 2001, compared to 2000, was primarily related to increased costs associated with properties acquired in the North Central acquisition, an $8,766,000 increase in severance taxes resulting from increased production from the Company s non-U.S. government owned properties, and to generally increased costs resulting from an industry-wide increase in demand for oil field services and equipment, that was only partially offset by decreased lease maintenance expenses. The increase in North American lease operating expenses for 2001, compared to 1999, was primarily related to increased costs associated with properties acquired in the North Central acquisition, an approximately $15,000,000 increase in severance taxes resulting from both increased production from the Company s non-U.S. government owned properties and increased prices that the Company received for that production, and generally increased costs resulting from an industry-wide increase in demand for oil field services and equipment, that was

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only partially offset by decreased lease maintenance expenses. The Company has noted that oil field service and equipment costs have generally begun to moderate in the second half of 2001, but expects that this trend is dependent on continued weakness in crude oil and natural gas prices.

The increase in lease operating expenses in the Kingdom of Thailand for 2001, compared to 2000, primarily related to increased expenses related to well workovers and increased insurance expenses related to construction of platforms for the Benchamas Field, as well as generally increasing costs resulting from an industry-wide increase in demand for oil field services and equipment. The increase in lease operating expenses in the Kingdom of Thailand for 2001, compared to 1999, primarily related to a full year s operations in Benchamas Field which commenced production in July 1999, increased expenses related to well workovers and increased insurance expenses related to construction of platforms for the Benchamas Field, as well as generally increasing costs resulting from an industry-wide increase in demand for oil field services and equipment and the presence in 1999 of a special credit related to contract services for which no equivalent benefit was experienced in 2001. A substantial portion of the Company s lease operating expenses in the Kingdom of Thailand relate to 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, $15,100,000 and $13,600,000 (net to the Company s interest) of the Company s Thailand lease operating expenses for 2001, 2000 and 1999, 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 five years. See Liquidity and Capital Resources; Capital Requirements; Other Material Long-Term Commitments.

Notwithstanding the overall increase in lease operating expenses, on a per unit of production basis, the Company s total lease operating expenses decreased slightly from an average of $0.77 per Mcfe for both 1999 and 2000, to $0.75 per Mcfe for 2001.

Pipeline Operating and Natural Gas Purchases

Revenue from the sale of natural gas purchased for resale is reported under Pipeline sales and other. Primarily all of the natural gas purchased and resold by the Company was transported on Pogo Onshore Pipeline Company s Saginaw pipeline. As previously discussed, this pipeline was sold in the fourth quarter of 2001 as part of the Company s ongoing asset rationalization process. The decrease in pipeline operating expenses and natural gas purchase costs for 2001, compared to 2000, primarily related to the decreased cost of natural gas purchased for resale by the Company. The increase in pipeline operating expenses and natural gas purchase costs for 2001, compared to 1999, primarily related to increased cost of natural gas purchased for resale by the Company.

General and Administrative Expenses

The increase in general and administrative expenses for 2001, compared with 2000 and 1999, primarily related to increased expenses associated with the Company s acquisition of North Central and its employees, as well as an increase in the size of the Company s work force and normal salary and concomitant benefit expense adjustments. Notwithstanding the overall increase in general and administrative expenses, on a per unit of production basis, the Company s general and administrative expenses declined to $0.25 per Mcfe in 2001, from $0.28 per Mcfe in 2000 and $0.32 per Mcfe in 1999.

Exploration Expenses

Exploration expenses consist primarily of rental payments required under oil and gas leases to hold non-producing properties (delay rentals) and geological and geophysical costs that are expensed as incurred. The increase in exploration expenses for 2001, compared to 2000 and 1999, resulted primarily from the cost of conducting two 3-D surveys in Hungary, the cost of transferring certain seismic licenses in connection with the North Central acquisition and the cost of acquiring substantial new speculative 3-D data sets in the Gulf of Mexico, for which no comparable expenses were incurred in either 2000 or 1999, which was partially offset in 1999 by acquisition costs related to the Company s Thibodaux 3-D survey.

Dry Hole and Impairment Expenses

Dry hole and impairment expenses relate to costs of unsuccessful wells drilled. Accounting rules 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. No such impairments are currently required on the Company s properties. 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. The decrease in the Company s dry hole and impairment expense for 2001, compared to 2000, resulted primarily from the comparative success of the Company s drilling program, that was partially offset by an impairment expense recorded earlier in 2001 on a non-operated property located in the offshore Gulf of Mexico that incurred unexpectedly high drilling and completion expenses. The increase in the Company s dry hole and impairment expense for 2001, compared to 1999, resulted from an increase in dry hole costs and the impairment expense discussed previously.

Depreciation, Depletion and Amortization Expenses

The Company accounts for its oil and gas activities using the successful efforts method of accounting. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. 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. 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. 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 substantially complete and ready for their intended use if projects are evaluated as successful. Other exploratory costs are expensed as incurred.

The provision for DD&A expense is based on the capitalized costs, as determined in the preceding paragraph, 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 2001, compared to 2000 and 1999, 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 2001, compared to 2000 and 1999, resulted primarily from 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 recent 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 Permian basin 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.

Interest

Interest Charges. The increase in the Company s interest charges for 2001, compared to 2000 and 1999, resulted primarily from an increase in the average amount of the Company s outstanding debt related to the acquisition of North Central, and to a much lesser extent, increased commitment fees and amortization of debt issuance expense, partially offset by a decline in the average interest rate on the outstanding debt.

Interest Income. The increase in the Company s interest income for 2001, compared to 2000 and 1999, resulted primarily from an increase in the amount of cash and cash equivalents temporarily invested, that was only partially offset by a decrease in the interest rate received. 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 caused by 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 increase in capitalized interest for 2001, compared to 2000 and 1999, resulted primarily from an increase in the amount of capital expenditures subject to interest capitalization during 2001 (approximately $365,000,000), compared to 2000 (approximately $248,000,000) and 1999 (approximately $217,000,000), that was only partially offset by a decrease in the computed rate that the Company uses to apply on such capital expenditures to arrive at the total amount of capitalized interest. A substantial percentage of the Company s capitalized interest expense 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 and several development projects in the Gulf of Mexico. The Company currently expects the amount of capital expenditures subject to interest capitalization to decrease during 2002 due to completion of fabrication of platforms and facilities to be installed in Thailand and in the offshore 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 owns all of the issued common securities, issued $150,000,000 of Trust Preferred Securities on June 2, 1999. The amounts recorded under Minority Interest Dividends and Costs Associated with Mandatorily Redeemable Convertible Preferred Securities of a Subsidiary Trust principally reflect cumulative unpaid 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 losses reported for 2001 and 2000 and the gain reported in 1999, resulted primarily from the fluctuation against the dollar of cash and other monetary assets and liabilities denominated in Thai Baht that were on Thaipo s and B8/32 Partners Limited s financial statements during the respective periods. During 2001, the Thai Baht dollar exchange rate fluctuated between 42.6 and 45.6 Baht to the dollar. The Company cannot predict what the Thai Baht to dollar exchange rate will be in the future. As of March 1, 2002, 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 decrease in the Company s tax expense for 2001, compared to 2000, resulted primarily from reevaluating certain estimates regarding its global tax and cash position and, as a result, recognizing certain additional tax benefits attributable to previously unrecognized Thai net operating loss carryforwards, partially offset by the provision for U.S. income taxes on certain unremitted foreign earnings and other tax adjustments. The increase in the Company s tax expense for 2001, compared to 1999, resulted primarily from an increase in pre-tax income. The Company s consolidated effective tax rate for 2001, 2000 and 1999 was 41%, 43% and 30%, respectively. The Company conducts its operations in taxing jurisdictions with varying tax rates. The relative proportion of the Company s income earned in each taxing jurisdiction affects the Company s consolidated effective tax rate.

Liquidity and Capital Resources

Cash Flows

The Company s Consolidated Statement of Cash Flows for 2001 reflects net cash provided by operating activities of $368,076,000, including receipts of $20,142,000 on natural gas option contracts purchased in 2000 in connection with the acquisition of North Central. See Quantitative and Qualitative Disclosures About Market

Risk Current Hedging Activity; Natural Gas. In addition to net cash provided by operating activities, the Company received proceeds of $200,000,000 from the issuance of the 2011 Notes, proceeds of $13,739,000 related to the sale of its Canadian operations, proceeds of $9,243,000 from the sale of certain non-core properties and other assets and $7,469,000 from the exercise of stock options. The Company also acquired $21,235,000 in cash and cash equivalents as part of its acquisition of North Central.

During 2001, the Company invested $386,164,000 of such cash flow in capital projects, paid former shareholders of NORIC $344,711,000 in partial consideration for their shares of NORIC capital stock, repaid $78,600,000 of debt that was acquired in the North Central acquisition, borrowed a net $229,990,000 under its revolving credit facility and other senior debt agreements, spent $2,714,000 to purchase proved reserves, paid $9,750,000 in cash dividends to holders of its Trust Preferred Securities, paid $6,047,000 ($0.03 per share for each quarter of 2001) in cash dividends to holders of the Company s common stock and paid $8,720,000 in financing issuance expenses. As of February 28, 2002, the Company s cash and cash investments were $109,943,000, its long-term debt stood at $804,989,000 and it had $150,000,000 in Trust Preferred Securities outstanding.

Future Capital Requirements

The Company s capital and exploration budget for 2002, 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 $340,000,000. The Company currently anticipates that its available cash and cash investments, cash provided by operating activities 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 and distribution payments at current levels. The declaration of future dividends on the Company s equity securities 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

Thaipo and its co-venturers in the Tantawan Field (collectively, the Charterers) are parties to a Charter Agreement (the Charter) with Tantawan Production B.V. for the charter of the FPSO for use in the Tantawan Field. See Business International Operations. The Charter expires on July 31, 2008, subject to extension. In addition, the Charterers have a purchase option on the FPSO throughout the term of the Charter at prices determined by reference to the Charter, which prices decline over time to a final purchase price of $5,000,000 ($2,317,000 net to Thaipo) at the end of the primary lease term. As of January 31, 2002, the purchase price for the FPSO was approximately $92,000,000 ($42,634,000 net to Thaipo). SBM Marine Services Thailand Ltd. has been contracted to operate the FPSO on a reimbursable basis throughout the initial term of the Charter. Liability on the Charter is full recourse as to each joint venturer, as to performance but the payment obligations are several, meaning that each joint venturer s payment obligations under the Charter are still limited to its percentage interest in the Tantawan Field. Thaipo s performance and payment obligations are fully and unconditionally guaranteed by the Company, but only as to Thaipo s pro rata share of the obligations arising under the Charter. The agreement to operate the FPSO is non-recourse to the Company. The Charter currently provides for a charter hire commitment of $22,865,000 per year ($10,596,000 net to Thaipo) through January 31, 2007, and a decreasing amount thereafter. As of January 1, 2002, the total remaining lease payment obligation on the FPSO amounted to $139,033,000 ($64,430,000 net to Thaipo).

As of August 24, 1998, the Charterers entered into a Bareboat Charter Agreement (the BCA) with Watertight Shipping B.V. for the charter of the FSO. See Business International Operations. The term of the BCA is for a period of ten years commencing on May 15, 1999. In addition, the Charterers have a purchase option on the FSO throughout the term of the BCA at prices determined by reference to the BCA, which prices decline over time to a final purchase price of $12,628,000 ($5,852,000 net to Thaipo) at the end of the primary lease term. The purchase price for the FSO as of January 31, 2002 was approximately $46,703,000 ($21,643,000 net to Thaipo). The Charterers have also contracted with another company, Tanker Pacific (Thailand) Co. Ltd, to operate the FSO on a fixed fee basis throughout the initial term of the BCA. Performance of both the BCA and the agreement to operate the FSO are non-recourse to the Company. However the obligations of each joint venturer are full recourse to each joint venturer, but the payment obligations under the BCA are several, meaning that each joint venturer s payment obligations are limited to its percentage interest in the Thailand Concession. The BCA currently provides for a charter hire commitment of $8,515,000 per year ($3,946,000 net to Thaipo). As of January 1, 2002, the total remaining lease payment obligation on the FSO amounted to $62,431,000 ($28,931,000 net to Thaipo).

Capital Structure

Credit Facility. Effective March 8, 2001, the Company terminated its existing credit facility and entered into a new 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 $425,000,000. The next redetermination of the borrowing base is expected to occur by May 1, 2002. 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 security 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 1.25%). 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 28, 2002, there was $215,000,000 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 uncommited 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 28, 2002, there was $24,989,000 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. In addition, they are senior in right of payment to the debentures held by Pogo Trust I relating to the Company s Trust Preferred Securities and the Company s guarantee of these debentures. See Liquidity and Capital Resources; Trust Preferred Securities. 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. In addition, they are senior in right of payment to the debentures held by Pogo Trust I relating to the Company s Trust Preferred Securities and the Company s guarantee of these debentures. See Liquidity and Capital Resources; Trust Preferred Securities. 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 3/4%, 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. In addition, they are senior in right of payment to the debentures held by Pogo Trust I relating to the Company s Trust Preferred Securities and the Company s guarantee of these debentures. See Liquidity and Capital Resources; Trust Preferred Securities. The Company, at its option, may redeem the 2007 Notes in whole or in part, at any time on or after May 15, 2002, at a redemption price of 104.375% of their principal value and decreasing percentages thereafter. 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, 2001. 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 1/2%, 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 and its banker s acceptances, its senior subordinated indebtedness, which currently includes the 2011 Notes, 2009 Notes and the 2007 Notes, but are senior in right of payment to the debentures held by Pogo Trust I relating to the Company s Trust Preferred Securities and the Company s guarantee of these debentures. See Liquidity and Capital Resources; Trust Preferred Securities. 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 102.75% of their principal. The redemption premium will decline over the next several years.

Trust Preferred Securities. Pogo Trust I, a business trust in which the Company owns all of the issued common securities (the Trust), issued 3,000,000 Trust Preferred Securities having a liquidation preference of $50 per Trust Preferred Security, on June 2, 1999. The proceeds from the issuance of the Trust Preferred Securities were used to purchase $150,000,000 of the Company s 6 1/2% Junior Subordinated Convertible Debentures, due 2029 (the Debentures). The Debentures are the sole asset of the Trust. The financial terms of the Debentures are generally the same as those of the Trust Preferred Securities. The Trust Preferred Securities accrue and pay distributions quarterly in arrears at a rate of 6 1/2% per annum on the stated liquidation amount of $50 per Trust Preferred Security on March 1, June 1, September 1, and December 1 of each year to securities holders of record on the business day immediately preceding the distribution payment date. The Company has guaranteed, on a subordinated basis, distributions and other payments due on the Trust Preferred Securities to the extent that there are funds available in the Trust. The Company currently believes that, taken as a whole, the Company s guarantee of the Trust s obligations under the Preferred Securities constitutes a full and unconditional guarantee by the Company of the Trust s performance obligations. The Company may cause the Trust to defer the payment of distributions for successive periods up to 20 consecutive quarterly periods unless an event of default on the Debentures has occurred and is continuing. During such periods, accrued distributions on the Trust Preferred Securities will compound quarterly and the Company will generally not be permitted to declare or pay distributions on its common stock or debt securities that rank equal or junior to the Debentures.

The Trust Preferred Securities are convertible at the option of the holder at any time into common stock of the Company at the rate of 2.1053 shares of Company common stock per Trust Preferred Security. This conversion rate will be subject to adjustment to prevent dilution and is currently equivalent to a conversion price of $23.75 per share of Company common stock. The Trust Preferred Securities are mandatorily redeemable upon maturity of the Debentures on June 1, 2029, or to the extent of any earlier redemption of any Debentures by the Company and are callable by the Trust at any time, in whole or in part, after June 1, 2002, at any time, at a redemption price of 104.55% of their principal. The redemption premium will decline over the next several years. In addition, if certain tax changes occur so that the Trust becomes subject to federal income taxes or interest payments made by the Company to the Trust on the Debentures are no longer deductible for federal income tax purposes, the Trust may liquidate and distribute Debentures to holders of the Trust Preferred Securities and, in certain circumstances, the Company may shorten the stated maturity of the Debentures to as early as June 2, 2014.

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 or the Memorandum of Understanding, in each case 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 and the Memorandum of Understanding, 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. A consortium of companies has raised this issue with PTT and the Government of Thailand, but no satisfactory resolution of this issue has yet been achieved.

The Company s crude oil and condensate production from the Thailand Concession is currently sold on a tanker load by tanker load basis. Prices that the Company receives for such production 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 recently issued two new pronouncements, Statement of Financial Accounting Standards No. 143 (SFAS 143), Accounting for Asset Retirement Obligations and Statement of Financial Accounting Standards No. 144 (SFAS 144), Accounting for the Impairment or Disposal of Long-Lived Assets.

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 currently intends to adopt this standard on January 1, 2003. Adoption of the standard will result in recording a cumulative effect of a change in accounting principle to earnings in the period of adoption. SFAS 143 will impact the way in which the Company, and most of the oil and gas industry, accounts for its future abandonment obligations. The Company has not yet quantified the financial statement impact from adoption of this new standard. However, the Company currently expects that initial adoption of SFAS 143 will result in a substantial positive accounting adjustment to earnings in the period it is adopted, but that earnings in subsequent periods will be negatively affected by a non-cash increase to DD&A expense and lease operating expenses. The Company also anticipates that the adoption of SFAS 143 will have a significant impact on the Company s balance sheet, resulting in a significant increase to both property and equipment and long-term liabilities.

SFAS 144. SFAS 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS 144 supersedes SFAS 121 but retains its fundamental provisions for the (a) recognition and measurement of impairment of long-lived assets to be held and used and (b) measurement of long-lived assets to be disposed of by sale. SFAS 144 also supersedes the accounting and reporting provisions of APB Opinion No. 30 for segments of a business to be disposed of, but retains the requirement to report discontinued operations separately from continuing operations and extends that reporting to a component of an entity that either has been disposed of, or is classified as held for sale. The Company adopted SFAS 144 effective January 1, 2002. Implementation of the new standard had no impact upon adoption and is not currently expected to have a material impact on the Company s financial position or results of operations in the future.

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 March 1, 2002, 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, 2001:

	2001	2002	2003	2004	2005	Thereafter	Total	Fair Value
Long-Term Debt:								
Variable Rate	$ 0	$ 0	$ 0	$ 0	$ 0	$ 229,990	$ 229,990	$ 229,990
Average Interest Rate						3.18%	3.18%	
Fixed Rate	$ 0	$ 0	$ 0	$ 0	$ 0	$ 565,000	$ 565,000	$ 575,719
Average Interest Rate						8.34%	8.34%	

Foreign Currency Exchange Rate Risk

In addition to the 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, 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 will continue to 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 and the Memorandum of Understanding 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 March 1, 2002, 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 Forint, is not material at this time.

Current Hedging Activity

From time to time, the Company has used and expects to continue to use hedging transactions with respect to a portion of its oil and gas production to achieve a more predictable cash flow, as well as to reduce its exposure to price fluctuations. While the use of these hedging arrangements limits the downside risk of adverse price movements, they may also limit future revenues from favorable price movements. The use of hedging transactions also involves the risk that the counter-parties will be unable to meet the financial terms of such transactions. All of the Company s recent historical hedging transactions have been carried out in the over-the-counter market with investment grade institutions. Approximately 16% of the Company s 2001 production, on an energy equivalent basis, or 29% of its natural gas production, was subject to commodity price hedging arrangements.

Natural Gas

As of December 31, 2001, the Company held options to sell 70 million cubic feet of natural gas production per day through December 31, 2002. These contracts give the Company the right, but not the obligation, to sell natural gas at a sales price of $4.25 per million British Thermal Units (MMBtu) for the period from January 2002 through March 2002 and $4.00 per MMBtu for the period from April 2002 through December 2002. These contracts are designed to guarantee a minimum floor price for the contracted volumes of production without limiting the Company s participation in price increases during the covered period. As of December 31, 2001, the Company was a party to the following hedging arrangements:

Contract Period	Volume in MMBtu(a)	NYMEX Contract Price per MMBtu(a)	Fair Value(b)
Floor Contracts:			
January 2002 March 2002	6,300	$ 4.25	$ 10,135,000
April 2002 December 2002	19,250	$ 4.00	$ 24,140,000

(a) MMBtu means million British Thermal Units.

(b) Fair value is calculated using prices derived from NYMEX futures contract prices existing at December 31, 2001.

These hedging transactions are settled based upon the average of the reported settlement prices on the NYMEX for the last three trading days or, occasionally, the penultimate trading day of a particular contract month. For any particular floor transaction, the counter-party 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. The Company is not required to make any payment in connection with the settlement of a floor transaction.

Crude Oil

As of March 1, 2002, the Company was not a party to any commodity price hedging contracts with respect to any of its current or future crude oil and condensate production.

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

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

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,		
	2001	**2000**	**1999**
	(Expressed in thousands, except per share amounts)		
Revenues:			
Oil and gas	$ 596,077	$ 479,202	$ 230,499
Pipeline sales and other	8,423	15,113	7,159
Gains on sales	1,000	3,676	37,458
Total	605,500	497,991	275,116
Operating Costs and Expenses:			
Lease operating	118,157	93,640	70,349
Pipeline operating and natural gas purchases	11,373	15,090	6,481
General and administrative	39,162	34,568	29,452
Exploration	23,373	15,291	5,982
Dry hole and impairment	26,945	28,608	4,594
Depreciation, depletion and amortization	206,609	131,151	104,266
Total	425,619	318,348	221,124
Operating Income	179,881	179,643	53,992
Interest:			
Charges	(56,259)	(34,064)	(35,874)
Income	3,226	2,634	1,208
Capitalized	33,242	20,918	17,733
Minority Interest Dividends and costs associated with mandatorily redeemable convertible preferred securities of a subsidiary trust	(9,999)	(9,965)	(5,914)
Foreign Currency Transaction Gain (Loss)	(524)	(3,174)	572
Income Before Taxes and Cumulative Effect of Change in Accounting Principle	149,567	155,992	31,717
Income Tax Expense	(61,613)	(66,969)	(9,583)
Income Before Cumulative Effect of Change in Accounting Principle	87,954	89,023	22,134
Cumulative Effect of Change in Accounting Principle		(1,768)	
Net Income	$ 87,954	$ 87,255	$ 22,134
Earnings (Loss) per Common Share:			
Basic			
Income before cumulative effect of change in accounting principle	$ 1.72	$ 2.20	$ 0.55
Cumulative effect of change in accounting principle		(0.04)	
Net income	$ 1.72	$ 2.16	$ 0.55
Diluted			
Income before cumulative effect of change in accounting principle	$ 1.62	$ 1.99	$ 0.55

Cumulative effect of change in accounting principle		(0.04)	
Net income	$ 1.62	$ 1.95	$ 0.55
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,	
	2001	**2000**
	(Expressed in thousands)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 94,294	$ 81,510
Accounts receivable	52,440	84,381
Other receivables	32,159	27,242
Federal income taxes receivable	27,441	
Deferred income tax	25,712	
Inventory product	3,129	3,054
Inventories tubulars	8,430	8,056
Price hedge contracts	34,275	9,153
Other	1,970	1,276
Total current assets	279,850	214,672
Property and Equipment:		
Oil and gas, on the basis of successful efforts accounting		
Proved properties	2,956,673	1,778,168
Unevaluated properties	257,158	75,150
Pipelines, at cost	775	7,095
Other, at cost	21,638	15,257
	3,236,244	1,875,670
Accumulated depreciation, depletion, and amortization		
Oil and gas	(1,133,560)	(1,053,478)
Pipelines	(739)	(1,780)
Other	(11,217)	(8,758)
	(1,145,516)	(1,064,016)
Property and equipment, net	2,090,728	811,654
Other Assets:		
Deferred income tax	13,359	34,822
Debt issue expenses	15,565	10,718
Foreign value added taxes receivable	6,200	7,262
Price hedge contracts		14,869
Other	20,706	20,652
	55,830	88,323
	$ 2,426,408	$ 1,114,649

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

POGO PRODUCING COMPANY & SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	December 31,	
	2001	**2000**
	(Expressed in thousands)	
LIABILITIES AND SHAREHOLDERS EQUITY		
Current Liabilities:		
Accounts payable operating activities	$ 34,962	$ 27,334
Accounts payable investing activities	94,523	67,703
Accrued interest payable	11,450	7,443
Foreign income taxes payable	7,966	
Accrued dividends associated with preferred securities of a subsidiary trust	813	813
Accrued payroll and related benefits	2,670	2,285
Deferred income tax	3,875	
Other	1,892	851
Total current liabilities	158,151	106,429
Long-Term Debt	794,990	365,000
Deferred Income Tax	488,639	126,580
Other Liabilities and Deferred Credits	14,657	13,456
Total liabilities	1,456,437	611,465
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	144,913
Shareholders Equity:		
Preferred stock, $1 par; 4,000,000 and 2,000,000 shares authorized, respectively		
Common stock, $1 par; 200,000,000 and 100,000,000 shares authorized, and 53,690,827 and 40,659,591 shares issued, respectively	53,691	40,660
Additional capital	659,227	298,885
Retained earnings	102,019	20,112
Accumulated other comprehensive income (loss)	10,272	(1,062)
Treasury stock (15,575 shares), at cost	(324)	(324)
Total shareholders equity	824,885	358,271
	$ 2,426,408	$ 1,114,649

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,		
	2001	**2000**	**1999**
	(Expressed in thousands)		
Cash flows from operating activities:			
Cash received from customers	$ 625,538	$ 446,184	$ 218,936
Cash received (paid) related to price hedge contracts	20,142	(24,022)	
Value added taxes received	1,062	4,763	101
Income taxes received	1,381	6,000	6,446
Operating, exploration and general and administrative expenses paid	(205,004)	(152,979)	(105,924)
Interest paid	(48,458)	(32,028)	(29,606)
Income taxes paid	(31,115)	(9,444)	(21,000)
Other	4,530	585	(196)
Net cash provided by operating activities	368,076	239,059	68,757
Cash flows from investing activities:			
Capital expenditures	(386,164)	(139,062)	(201,323)
Acquisition of NORIC, net of $21,235,000 cash acquired	(323,476)		
Purchase of proved reserves	(2,714)	(8,393)	(20,000)
Proceeds from the sale of Canadian subsidiary	13,739		
Proceeds from the sale of property and tubular stock	9,243	3,745	81,944
Net cash used in investing activities	(689,372)	(143,710)	(139,379)
Cash flows from financing activities:			
Proceeds from issuance of new debt	200,000		150,000
Proceeds from issuance of new financing			150,000
Borrowings under senior debt agreements	1,322,990	67,000	260,053
Payments under senior debt agreements	(1,093,000)	(77,000)	(470,000)
Payment of North Central senior debt acquired	(78,600)		
Proceeds from exercise of stock options	7,469	6,115	1,115
Payment of preferred dividends of a subsidiary trust	(9,750)	(9,750)	(4,999)
Payment of cash dividends on common stock	(6,047)	(4,852)	(4,825)
Payment of financing issue expenses	(8,720)	(135)	(12,347)
Net cash provided by (used in) financing activities	334,342	(18,622)	68,997
Effect of exchange rate changes on cash	(262)	(1,484)	(67)
Net increase (decrease) in cash and cash equivalents	12,784	75,243	(1,692)
Cash and cash equivalents at the beginning of the year	81,510	6,267	7,959
Cash and cash equivalents at the end of the year	$ 94,294	$ 81,510	$ 6,267
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 87,954	$ 87,255	$ 22,134
Adjustments to reconcile net income to net cash provided by operating activities			
Cumulative effect of change in accounting principle		1,768	
Minority interest	9,999	9,965	5,914
Foreign currency transaction (gain) loss	524	3,174	(572)
Gains on sales	(1,000)	(3,676)	(37,458)
Depreciation, depletion and amortization	206,609	131,151	104,266

Dry hole and impairment	26,945	28,608	4,594
Interest capitalized	(33,242)	(20,918)	(17,733)
Price hedge contracts	5,550	(24,022)	
Increase (decrease) in deferred income taxes	50,617	57,969	(11,417)
Change in assets and liabilities:			
(Increase) decrease in accounts receivable	40,436	(48,425)	(13,006)
(Increase) decrease in federal income taxes receivable	(22,809)	5,526	6,080
(Increase) decrease in inventory product	12	601	(6,117)
(Increase) decrease in other current assets	(534)	1,062	453
Decrease in other assets	6,257	2,902	41
Increase (decrease) in accounts payable	(17,786)	5,447	9,714
Increase in foreign income taxes payable	3,684		
Increase (decrease) in accrued interest payable	4,010	(14)	4,314
Increase in accrued payroll and related benefits	385	132	201
Increase (decrease) in other current liabilities	(241)	624	210
Increase (decrease) in deferred credits	706	(70)	(2,861)
Net cash provided by operating activities	$ 368,076	$ 239,059	$ 68,757

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	Additional Capital	Retained Earnings (Deficit)	Accumulated Other Compre-hensive Income (Loss)	Treasury Stock	Share-holders' Equity	Compre-hensive Income (Loss)
Balance at December 31, 1998	40,136	$ 290,655	$ (79,600)	$ (1,207)	$ (324)	$ 249,660	
Net income			22,134			22,134	$ 22,134
Exercise of stock options	130	1,267				1,397	
Adjustment for fractional shares and other	13	(13)					
Dividends ($0.12 per common share)			(4,825)			(4,825)	
Exchange gain on Canadian currency				146		146	146
Comprehensive income							$ 22,280
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	
Reclassification adjustment included in net income related to sale of Canadian subsidiary				673		673	
Net exchange gain on Canadian currency							
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
Balance at December 31, 2001	53,691	$ 659,227	$ 102,019	$ 10,272	$ (324)	$ 824,885	

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. 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. See note 4 of the notes to consolidated financial statements for a discussion of the Company s accounting for its minority interest in Pogo Trust I.

Prior-Year Reclassifications

Certain prior-year amounts have been reclassified to conform with the current year presentation.

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 Hungarian 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.

Production Imbalances

Owners of an oil and gas property often take more or less production from a property than entitled based on their ownership percentages in the property. This results in a condition known in the industry as a production imbalance. The Company follows the sales (takes or cash) method of accounting for production imbalances

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

whereby the Company recognizes revenues on production as it is taken and delivered to its purchasers not withstanding its ownership percentage. The Company s crude oil imbalances are not significant. At December 31, 2001, the Company had taken approximately 2,949 MMcf of natural gas less than it was entitled to based on its interest in those properties, and approximately 905 MMcf more than its entitlement on other properties placing the Company at year-end in a net under-delivered position of approximately 2,044 MMcf of natural gas based on its working interest ownership in the properties.

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 SEC) Staff Accounting Bulletin No. 101, Revenue Recognition. As a result, the oil and gas exploration and production industry s long-standing historical practice of recording such product inventories at their net realizable value is no longer accepted by the SEC. The product inventory at December 31, 2000 consisted of approximately 350,000 barrels of crude oil and condensate, net to the Company s interest, and is carried at its estimated average cost of $8.73 per barrel. 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 following summary presents the pro forma consolidated results of operations as if the accounting change had occured as of the beginning of 1999. The pro forma results are expressed in thousands of dollars, except for per share amounts.

	2000	1999
Pro forma:		
Revenues	$ 497,991	$ 268,876
Operating income	$ 179,643	$ 50,456
Net income	$ 89,023	$ 20,366
Earnings per share:		
Basic	$ 2.20	$ 0.51
Diluted	$ 1.99	$ 0.50
As reported:		
Earnings per share:		
Basic	$ 2.16	$ 0.55
Diluted	$ 1.95	$ 0.55

The product inventory at December 31, 2001 consists of approximately 260,087 barrels of crude oil and condensate, net to the Company s interest, and is carried at the Company s 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.

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 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
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

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

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	For the Year Ended December 31, 1999		
	Income	**Shares**	**Per Share**
Basic earnings per share	$ 22,134	40,178	$ 0.55
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		212	
Diluted earnings per share	$ 22,134	40,390	$ 0.55
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	$	2,388	$ 21.46
Interest expense incurred, net of taxes, and shares not issued related to the assumed non-conversion at $42.185 per share of the 2006 Notes	$ 4,111	2,726	$ 1.51
Minority interest expense incurred, net of taxes, and shares not issued related to the assumed non-conversion at $23.75 per share of the Trust Preferred Securities, issued on June 2, 1999	$ 3,681	3,668	$ 1.00

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 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.

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 felt were underperforming, had little or no remaining upside potential, or faced 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.

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 to be cash equivalents. Significant transactions may occur which do not directly affect cash balances and, as such, will not be disclosed in the Consolidated Statements of Cash Flows. Certain such noncash transactions are disclosed in the Consolidated Statements of Shareholders Equity relating to shares issued in connection with 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 and for an FPSO and FSO in the Gulf of Thailand. Rental expense for office space was $2,623,000 in 2001, $1,911,000 in 2000, and $1,855,000 in 1999. Expenses for the FPSO lease were approximately $10,600,000 in 2001 and $11,100,000 in each of the years 2000 and 1999. Expenses for the FSO (which commenced in May 1999) were approximately $4,000,000 in each of the years 2001 and 2000 and $2,500,000 in 1999. Future minimum lease expenses in connection with its operating leases at December 31, 2001 are approximately $17,600,000 in each of the years 2002 through 2006 and $35,900,000 thereafter.

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.

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Price Risk Management

The Company from time to time enters into commodity price hedging contracts with respect to its oil and gas production to limit 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. In 1999, the company hedged 3,175 MMcf of natural gas and 514,500 barrels of crude oil (6,262 equivalent MMcf) or approximately 7% of its equivalent 1999 production and recorded hedge gains of $933,000 in connection with its natural gas contracts and hedge gains of $1,947,000 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

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. Based on interpretive guidance issued during the first quarter of 2001, the Company determined that the cumulative effect of adopting SFAS 133 should be recorded in other comprehensive income. As such, effective January 1, 2001, the Company recorded an unrealized loss of $2,438,000, net of deferred taxes of $1,313,000, in other comprehensive income (loss).

Recent Accounting Pronouncements

The FASB has recently issued two new pronouncements, Statement of Financial Accounting Standards No. 143 (SFAS 143), Accounting for Asset Retirement Obligations and Statement of Financial Accounting Standards No. 144 (SFAS 144), Accounting for the Impairment or Disposal of Long-Lived Assets.

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 currently intends to adopt this standard on January 1, 2003. Adoption of the standard will result in recording a cumulative effect of a change in accounting principle to earnings in the period of adoption. SFAS 143 will impact the way in which the Company, and most of the oil and gas industry, accounts for its future abandonment obligations. The Company has not yet quantified the financial statement impact from adoption of this new standard.

SFAS 144 addresses the financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS 144 supersedes SFAS 121 but retains its fundamental provisions for the (a) recognition and measurement of impairment of long-lived assets to be held and used and (b) measurement of long-lived assets to be disposed of by sale. SFAS 144 also supersedes the accounting and reporting provisions of APB Opinion No. 30 for segments of a business to be disposed of, but retains the requirement to report discontinued operations separately from continuing operations and extends that reporting to a component of an entity that either has been disposed of or is classified as held for sale. The Company adopted SFAS 144 effective January 1, 2002.

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Implementation of the new standard had no impact upon adoption and is not currently expected to have a material impact on the Company s financial position or results of operations in the future.

(2) Income Taxes

The components of income before income taxes for each of the three years in the period ended December 31, 2001, are as follows (expressed in thousands):

	2001	2000	1999
United States	$ 81,619	$ 67,967	$ 40,472
Foreign	67,948	88,025	(8,755)
Income before income taxes and cumulative effect of change in accounting principle	$ 149,567	$ 155,992	$ 31,717

The components of income tax expense (benefit) for each of the three years in the period ended December 31, 2001, are as follows (expressed in thousands):

	2001	2000	1999
Current			
United States	$	$ 9,000	$ 21,000
Foreign	10,996		
Deferred			
United States	59,823	12,392	(6,978)
Foreign	(9,206)	45,577	(4,439)
Income tax expense	$ 61,613	$ 66,969	$ 9,583

Total income tax expense for each of the three years in the period ended December 31, 2001, 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):

	2001	2000	1999
Federal statutory income tax rate	35.0%	35.0%	35.0%
Increases (reductions) resulting from:			
Foreign income taxed at different rates	11.3	8.7	(4.1)
Recognition of previously unbenefitted loss carryforwards	(20.4)		
U.S. taxes on repatriation of foreign earnings	5.7		
State income taxes, net of federal benefit	4.0		
Other	5.6	(0.8)	(0.7)
	41.2%	42.9%	30.2%

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Deferred income taxes are determined based upon the differences between the financial statement and tax basis of the Company s assets and liabilities using enacted tax rates in effect for the years in which the differences are expected to reverse. Deferred tax assets are recognized if it is more likely than not that the future tax benefit will be realized. The principal components of the Company s deferred income tax assets and liabilities at December 31, 2001 and 2000 (expressed in thousands) are as follows:

	December 31,	
	2001	**2000**
Deferred tax assets:		
Foreign net operating loss carryforwards	$ 39,071	$ 65,302
Valuation allowance		(30,480)
Other	5,055	
	44,126	34,822
Deferred tax liabilities:		
Book basis in excess of tax basis in oil and gas properties and equipment	(490,496)	(126,580)
Book basis in excess of tax basis in price hedge contracts	(5,531)	
Unremitted foreign earnings	(1,040)	
Other	(502)	
	(497,569)	(126,580)
Net deferred tax liability	$ (453,443)	$ (91,758)

Book basis in excess of tax basis in 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, 2001, the Company has net operating loss carryforwards, principally from its operation in Thailand, of approximately $75,700,000 which are available to offset future income tax. The Thai net operating loss carryforwards will begin to expire in 2007.

The Company does not provide for U.S. income taxes on unremitted earnings of foreign subsidiaries where the Company s present intention is to reinvest the unremitted earnings in its foreign operations. Unremitted earnings of foreign subsidiaries for which U.S. income taxes have not been provided are approximately $57,500,000 at December 31, 2001. 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 has 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.

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(3) Long-Term Debt

Long-term debt and the amount due within one year at December 31, 2001 and 2000, consists of the following (dollars expressed in thousands):

	December 31, 2001	December 31, 2000
Senior debt		
Bank revolving credit agreement:		
LIBOR based loans, borrowings at interest rate of 3.1875%	$ 185,000	$
Prime based loans, borrowings at an interest rate of 4.75%	10,000	
Swing line money market loans, borrowings at interest rate of 3.3125%	10,000	
Banker s Acceptance loans, borrowings at interest rate of 2.45%	24,990	
Total senior debt	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	
5 1/2% Convertible subordinated notes, due 2006	115,000	115,000
Total subordinated debt	565,000	365,000
Total debt	794,990	365,000
Amount due within one year		
Long-term debt	$ 794,990	$ 365,000

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 $425,000,000. 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 security 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.25%). 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 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

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 3/4%, 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. In addition, they are senior in right of payment to the debentures held by Pogo Trust I relating to the Company s Trust Preferred Securities described in Note 4 and the Company s guarantee of these debentures. The Company, at its option, may redeem the 2007 Notes in whole or in part, at any time on or after May 15, 2002, at a redemption price of 104.375% of their principal value and decreasing percentages thereafter. 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. In addition, they are senior in right of payment to the debentures held by Pogo Trust I relating to the Company s Trust Preferred Securities described in Note 4 and the Company s guarantee of these debentures. 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 1/4%, 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. In addition, they are senior in right of payment to the debentures held by Pogo Trust I relating to the Company s Trust Preferred Securities described in Note 4 and the Company s guarantee of these debentures. 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. As of December 31, 2001, $55,759,000 was available for dividends under this limitation, which is currently the Company s most restrictive covenant.

The outstanding principal amount of 2006 Notes was $115,000,000 as of December 31, 2001. The 2006 Notes bear interest at a rate of 5 1/2%, payable semi-annually in arrears on June 15 and December 15 of each year.

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, but are senior in right of payment to the debentures held by Pogo Trust I relating to the Company s Trust Preferred Securities described in Note 4, and the Company s guarantee of these debentures. 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 102.75% 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 four years in connection with the above long-term debt. In 2006, maturities of $344,990,000 will become due consisting of the senior debt currently outstanding and the outstanding principal of the 2006 Notes.

(4) Minority Interest

Pogo Trust I, a business trust in which the Company owns all of the issued common securities (the Trust), issued $150,000,000 (3,000,000 securities having a liquidation preference of $50 each) of 6 1/2% Cumulative Quarterly Income Convertible Preferred Securities, Series A (the Trust Preferred Securities) on June 2, 1999. The proceeds of the issuance of the Trust Preferred Securities were used to purchase $150,000,000 of the Company s 6 1/2% Junior Subordinated Convertible Debentures, due June 1, 2029 (the Debentures). The Debentures are the sole asset of the Trust. The financial terms of the Debentures are generally the same as those of the Trust Preferred Securities. The Trust Preferred Securities accrue and pay distributions quarterly in arrears at a rate of 6 1/2% per annum on the stated liquidation amount of $50 per Trust Preferred Security on March 1, June 1, September 1, and December 1 of each year to security holders of record on the business day immediately preceding the distribution payment date. The Company has guaranteed, on a subordinated basis, distributions and other payments due on the Trust Preferred Securities to the extent that there are funds available in the Trust.

The Company currently believes that, taken as a whole, the Company s guarantee of the Trust s obligation under the Preferred Securities constitutes a full and unconditional guarantee by the Company of the Trust s performance obligation. The Company may cause the Trust to defer the payment of distributions for successive periods up to 20 consecutive periods unless an event of default on the Debentures has occurred and is continuing. During such periods, accrued distributions on the Trust Preferred Securities will compound quarterly and the Company will generally not be permitted to declare or pay distributions on its common stock or debt securities that rank equal or junior to the Debentures.

The Trust Preferred Securities are convertible at the option of the holder at any time into common stock of the Company at the rate of 2.1053 shares of Company common stock per Trust Preferred Security. This conversion rate will be subject to adjustment to prevent dilution and is currently equivalent to a conversion price of $23.75 per share of Company stock. The Trust Preferred Securities are mandatorily redeemable upon maturity of the Debentures on June 1, 2029, or to the extent of any earlier redemption of any Debenture by the Company and are callable by the Trust, in whole or in part, at any time after June 1, 2002, at any time, at a redemption price of 104.55% of their principal. The redemption premium will decline over the next several years. In addition, if certain tax changes occur so that the Trust becomes subject to federal income taxes or if interest payments made by the Company to the Trust or the Debentures are no longer deductible for federal income tax purposes, the Trust may liquidate and distribute the Debentures to holders of the Trust Preferred Securities and, in certain circumstances, the Company may shorten the stated maturity of the Debentures to as early as June 2, 2014.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(5) Business Segment Information

The Company has three reportable segments, which are primarily in the business of natural gas and crude oil exploration and production. 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, 2001:				
United States	$ 1,748,046	$ 1,741,035	$ 36	$ 6,975
Kingdom of Thailand	342,411	338,965		3,446
Other	271	271		
Total	$ 2,090,728	$ 2,080,271	$ 36	$ 10,421
As of December 31, 2000:				
United States	$ 462,530	$ 454,246	$ 5,315	$ 2,969
Kingdom of Thailand	337,317	334,018		3,299
Canada and other	11,807	11,576		231
Total	$ 811,654	$ 799,840	$ 5,315	$ 6,499
Capital Expenditures:				
(including interest capitalized)				
As of December 31, 2001:				
United States	$ 1,458,549	$ 1,453,756	$	$ 4,793
Kingdom of Thailand	73,192	73,192		
Other	3,071	3,071		
Total	$ 1,534,812	$ 1,530,019	$	$ 4,793
As of December 31, 2000:				
United States	$ 117,749	$ 117,040	$	$ 709
Kingdom of Thailand	60,906	60,906		
Canada and other	8,157	8,157		
Total	$ 186,812	$ 186,103	$	$ 709
Revenues:				
For the year ended December 31, 2001:				
United States	$ 417,503	$ 408,514	$ 12,037	$ (3,048)
Kingdom of Thailand	183,074	183,005		69
Canada and other	4,923	4,558		365
Total	$ 605,500	$ 596,077	$ 12,037	$ (2,614)

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
For the year ended December 31, 1999:				
United States	$ 217,339	$ 172,683	$ 7,462	$ 37,194
Kingdom of Thailand	54,444	54,480		(36)
Canada	3,333	3,336		(3)
Total	$ 275,116	$ 230,499	$ 7,462	$ 37,155

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Total Company	Oil and Gas	Pipelines	Corporate & Other
	(Expressed in thousands)			
Depreciation, depletion, and amortization expense:				
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
For the year ended December 31, 1999:				
United States	$ 75,378	$ 73,886	$ 235	$ 1,257
Kingdom of Thailand	27,683	27,174		509
Canada	1,205	1,205		
Total	$ 104,266	$ 102,265	$ 235	$ 1,766
Operating income (loss):				
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
For the year ended December 31, 1999:				
United States	$ 59,130	$ 21,564	$ 372	$ 37,194
Kingdom of Thailand	(3,491)	(3,455)		(36)
Canada	(1,647)	(1,644)		(3)
Total	$ 53,992	$ 16,465	$ 372	$ 37,155

(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, 2001 sales have been presented for those customers who have in either of the previous two years exceeded 10% of revenues (expressed in thousands):

	2001	2000	1999
Petroleum Authority of Thailand (PTT)	$ 54,712	$ 46,930	$ 24,315
Enron Corp. and affiliates	$ 96,970	$ 66,083	$ 10,911

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(7) Credit Risk

Substantially all of the Company s accounts receivable at December 31, 2001 and 2000, result from oil and gas sales and joint interest billings to other companies in the oil and gas 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.

During 1999, 2000 and 2001, 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. As of December 31, 2001, 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.

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.

All of the Company s current natural gas production from its Thailand operations are committed under a long-term Gas Sales Agreement and a Memorandum of Understanding to PTT at prices denominated in Thai baht. The Company s crude oil and condensate production from its Thailand operations is currently sold on a tanker load by tanker load basis. Prices that the Company receives for such crude oil production are based on world benchmark prices, which are denominated in U.S. dollars and are generally expected to be paid in U.S. dollars.

(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 his 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 $928,000 to the savings plan in 2001, $886,000 in 2000, and $963,000 in 1999.

A trusteed retirement plan has been adopted by the Company 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

POGO PRODUCING COMPANY & SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 which can be deducted for federal income tax purposes. 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, 2001 and 2000.

	Retirement Plan		Post-Retirement Medical Plan	
	2001	2000	2001	2000
Change in benefit obligation				
Benefit obligation at beginning of year	$ 14,979	$ 11,469	$ 8,002	$ 7,087
Service cost	1,577	1,012	602	441
Interest cost	1,144	920	556	535
Plan amendments	499			
Acquisitions/divestitures			737	
Benefits paid	(413)	(1,568)	(212)	(105)
Actuarial loss	1,234	3,146	219	44
Benefit obligation at end of year	$ 19,020	$ 14,979	$ 9,904	$ 8,002
Change in plan assets				
Fair value of plan assets at beginning of year	$ 38,337	$ 37,299	$	$
Actual return on plan assets	(4,145)	2,967		
Employer contributions			212	105
Benefits paid	(413)	(1,568)	(212)	(105)
Administrative expenses	(314)	(361)		
Fair value of plan assets at end of year	$ 33,465	$ 38,337	$	$
Reconciliation of funded status			&n	