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# WESTERN GAS RESOURCES

Annual Report 2002

AR/S 1-10389

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## WESTERN GAS RESOURCES, INC.

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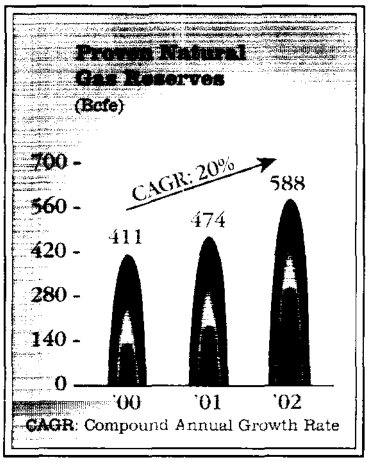
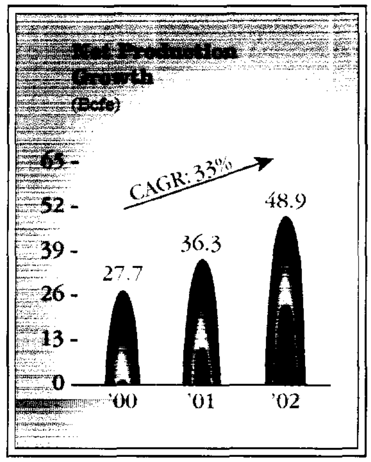
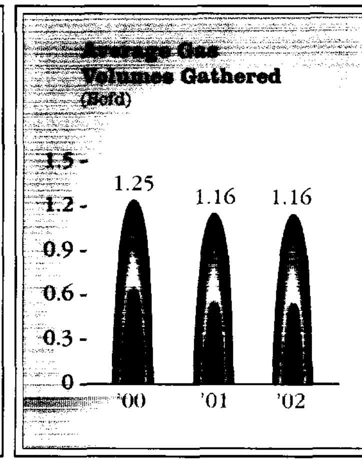


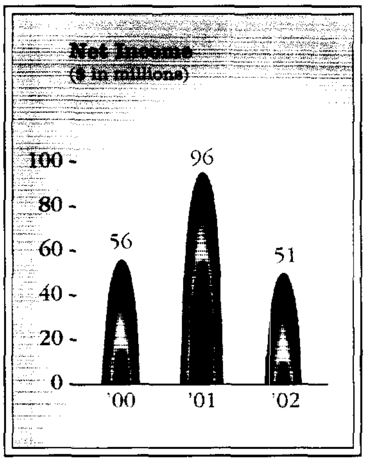



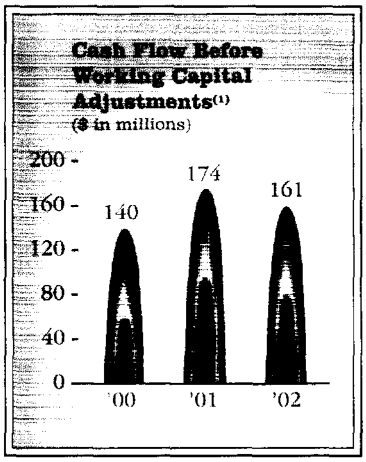

# ★ Segment Operating Data ★

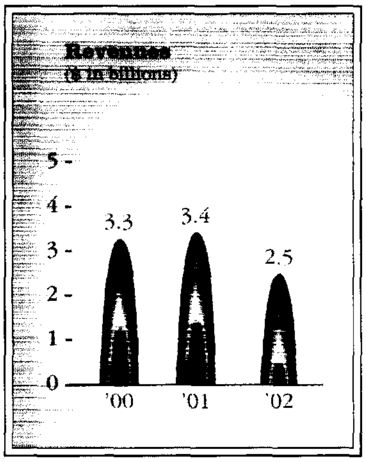
(Operating Profit—dollars in thousands)

| Year ended December 31, | 2002 | 2001 | 2000 |
|---|---|---|---|
| Production: | | | |
| Equity gas reserves (Bcfe) | **588** | 474 | 412 |
| Gas production volumes (MMcfed) | **134** | 100 | 76 |
| Average gas prices ($/Mcfe) | **$ 2.34** | $ 3.16 | $ 3.07 |
| Operating profit[1] | **$73,734** | $ 64,395 | $ 28,801 |
| Gas Gathering and Processing: | | | |
| Connected gas reserves (Tcf) | **3.6** | 3.2 | 2.7 |
| Average gas volumes gathered (MMcfd) | **1,163** | 1,161 | 1,248 |
| Average plant gas sales (MMcfd) | **447** | 412 | 406 |
| Average plant NGL sales (MGald) | **1,417** | 1,455 | 1,505 |
| Operating profit[1] | **$92,870** | $135,834 | $138,395 |
| Transportation: | | | |
| Gas transportation volumes (MMcfd) | **192** | 193 | 187 |
| Operating profit[1] | **$15,715** | $ 16,468 | $ 17,302 |
| Marketing: | | | |
| Average gas sales (MMcfd) | **1,988** | 1,961 | 1,835 |
| Average NGL sales (MGald) | **2,010** | 2,347 | 3,085 |
| Average gas prices ($/Mcf) | **$ 2.92** | $ 3.97 | $ 3.90 |
| Average NGL prices ($/Mcf) | **$ .42** | $ .49 | $ .52 |
| Average gas sales margin ($/Mcf) | **$ .04** | $ .06 | $ .02 |
| Average NGL sales margin ($/Gal) | **$ .008** | $ .005 | $ .007 |
| Operating profit[1] | **$37,490** | $ 50,030 | $ 19,474 |

(1) Operating profit represents total revenues less product purchases, plant and transportation operating expense and oil and gas exploration and production expense.




# ★ Selected Financial Data ★

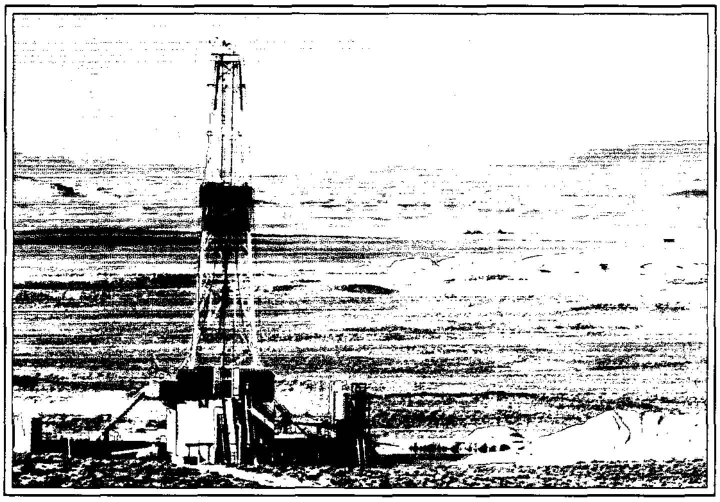
(Dollars in thousands, except share and per share amounts)

| Year ended December 31, | 2002 | 2001 | 2000 |
|---|---|---|---|
| Revenues | **$ 2,489,698** | $ 3,353,162 | $ 3,280,091 |
| Net income | **50,589** | 95,637 | 56,108 |
| Earnings per share of common stock—assuming dilution | **1.23** | 2.48 | 1.39 |
| Weighted average shares of common stock outstanding—assuming dilution | **33,607,560** | 37,022,369 | 32,834,641 |
| Total Assets | **1,302,144** | 1,267,942 | 1,431,422 |
| Long-term debt | **359,933** | 366,667 | 358,700 |
| Stockholder's equity | **483,068** | 473,352 | 391,534 |
| Cash flow before working capital adjustments(1) | **161,071** | 173,506 | 139,879 |
| Capital expenditures | **140,637** | 163,977 | 108,536 |

(1) See page 85 for reconciliation to net income.

# ★ 2002 Operational Highlights ★

- Achieved shareholder return of 14.6 percent.
- Realized net income of $50.6 million or $1.23 per diluted share.
- Increased proved reserves 24 percent to 588 Bcfe.
- Increased net production 34 percent to 49 Bcfe.
- Replaced 332 percent of equity gas produced.
- Incurred finding and development costs of only $0.43 per Mcf.
- Maintained steady gathering & processing volumes.
- Replaced 205 percent of reserves connected to midstream facilities.
- Reduced debt to capitalization ratio to 43 percent.
- Redeemed remaining $2.28 preferred stock.



# ★ Table of Contents ★



*Front Cover: Durham Ranch, Powder River Basin Coal Bed Methane Development*

# ★ Western Gas Resources ★

★ **Western** focus

★ **Gas** leveraged

★ **Resource** rich

**Western** Gas Resources explores, produces, gathers, processes, transports and markets natural gas and natural gas liquids in the western United States. Our primary focus area for growth is the Rocky Mountain region, given the large natural gas resource base. Western's human and financial resources are the key to unlocking the significant shareholder value of our 2.6 Tcf of proven and unrisked probable and possible gas reserves under lease and 3.6 Tcf of proven reserves connected to our midstream facilities. Our extensive inventory of long-term, low-cost, low-risk and high-return reserves will fuel Western's upstream and midstream growth throughout the decade.

Western Gas Resources — Our name says it all.

# ★ Dear Shareholders ★

Western Gas Resources, as our name implies, is strategically focused on the vast natural gas resource in the West. Unconventional resources such as coal bed methane (CBM) in the Powder River Basin and low permeability or "tight" gas sands in the Green River Basin provide Western with the leasehold to steadily grow our proved reserves. Our expertise and assets in natural gas gathering, processing, transportation and marketing provide Western with strategic competitive advantages—the ability to control our own destiny in getting our natural gas and natural gas liquids to market, achieve the best possible prices and generate substantial cash to fund our growth projects. Western's newly established exploration and acquisition team and our existing business development team will further enhance our portfolio with new Company building projects.

Why natural gas? As America's population grows and depends more on technology, Americans rely more on natural gas to heat, cool and provide electricity for their homes, businesses and industries. During the last few decades, America increasingly turned to natural gas since it is the most clean-burning and environmentally friendly dependable fuel. Industry responded with substantial investments in the exploration, development and transportation of natural gas.

Today, industry faces growing challenges in bringing new supplies of natural gas to market, especially in the gas rich Rocky Mountain region. Base decline of United States gas production, without additional drilling, has declined further to 27 percent per year. Meanwhile, per well reserves and productivity are diminishing. Nearly twice the number of wells are required this year versus a decade ago to offset the base decline to maintain flat production. In the early 1990's, 500 gas rigs drilling year-round would have offset the base decline. Now 900 to 1,000 gas rigs are required. Additionally, a reduced workforce, volatile prices and more fiscal discipline have resulted in a low inventory of exploration prospects. We concur with many industry experts who believe that natural gas prices will remain strong due to the tight supply-demand dynamics.

Overall, Western's focus on natural gas stems from our profitable track record in finding and delivering gas to market in a region known for its vast resource, a favorable outlook on commodity prices and our desire to deliver environmentally friendly fuel to America's homes and businesses.

**★ Our experience in the exploration, production and gathering of unconventional gas reservoirs provides an ideal combination to capitalize on the Rocky Mountain basins. ★**

## Eighty-five percent of the estimated natural gas resource base of the Rocky Mountain region has yet to be discovered or developed.

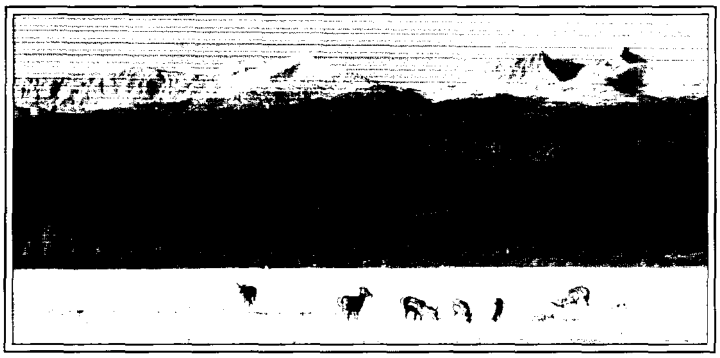
Why the Rockies? Eighty-five percent of the estimated natural gas resource base of the Rocky Mountain region has yet to be discovered or developed. The undiscovered portion alone is estimated to approach 200 trillion cubic feet (Tcf). A major part of this resource is in the Powder River and Green River Basins of Wyoming. Western holds significant leasehold and operations in these two prolific basins. Over 92 percent of the Rockies resource potential is from unconventional reservoirs such as CBM and tight gas sands. Our related experience provides an ideal combination to capitalize on the resource rich Rocky Mountain basins.

Western Gas experienced another excellent year in 2002. Our employees and assets delivered net income of $50.6 million and cash flow before working capital adjustments of $161.1 million, which resulted in a 14.6 percent total return to our shareholders. We increased net production 34 percent to 49 billion cubic feet (Bcf) by participating in 937 gross wells with a 98 percent success rate. Our production growth came organically from the drill bit at finding and development costs of less than 50 cents per thousand cubic feet (Mcf), nearly one-third of industry averages. We also continued our strong record of reserve additions. We increased proved reserves 24 percent to 588 billion cubic feet of gas equivalent (Bcfe). The Company replaced 332 percent of 2002 production.

Most importantly, we believe the best is yet to come for Western Gas. Our existing leasehold in two of the most prolific natural gas plays in the United States offers tremendous potential with unrisked probable and possible reserves of approximately two Tcf. The Powder River Basin is producing nearly one Bcf per day by industry, mostly from the Wyodak and related coals. The prolific Big George coal has come on strong from several pilots in the last two years. The Big George coal is producing 70 million cubic feet per day (MMcfd) from industry, similar to the Wyodak in early 1998. It could exceed the production of the Wyodak given its greater thickness, pressure and gas content. We remain the largest gatherer and transporter in the Powder River Basin, as volumes gathered increased 33 percent to 381 MMcfd in 2002 compared to 2001.

The Pinedale Anticline in the Green River Basin is producing a total of

Powder River Basin



Pinedale Anticline

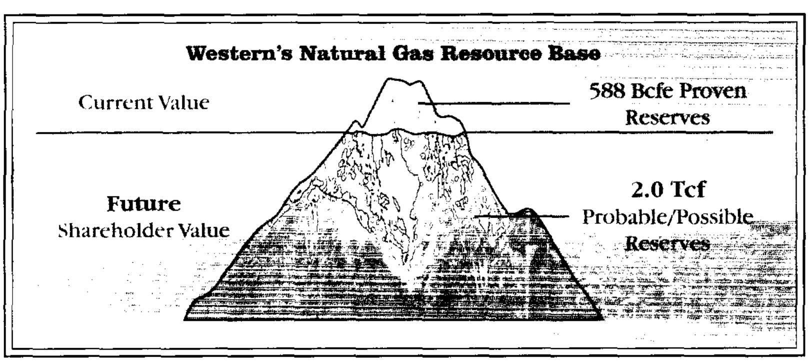
approximately 275 MMcfd from industry in just five years of development. It is in the early stages of development as Western has exposure to an additional 500 wells in this play. We enhanced our fully integrated operations in 2002 by completing the first two phases of our 50-percent owned Rendezvous gathering system. Rendezvous can now gather 275 MMcfd of equity and third-party gas from the Pinedale Anticline and deliver that gas to two processing facilities including Western's Granger system.

Western's integrated approach to the natural gas business differentiates us from many of our peers. Our significant gathering and processing operations complement our production activities and our marketing strategy has provided superior price risk management. As a result of favorable equity gas hedges and firm transportation agreements, we mitigated the impact of weaker natural gas prices in the Rocky Mountain region in 2002. In fact, over 90 percent of our production was insulated from Rockies gas prices. Additionally, we have effectively eliminated our exposure to Rockies pricing for our production volumes in 2003. We have hedged 53 percent of our equity gas and the remainder will benefit from Mid-Continent pricing utilizing our firm transportation.

Our midstream assets in West Texas, northern Oklahoma and northwest New Mexico also performed exceptionally well during 2002. Modernization upgrades and new automation reduced operating expenses by $4 million in 2002 and should result in greater savings in 2003. Gathering and processing volumes remained steady through active drilling and new contracts.

Overall, our midstream operations contributed $93 million, or 42 percent of the Company's operating profit in 2002. Proven reserves connected to our systems increased approximately 400 Bcf in 2002 to 3.6 Tcf. New drilling activity continues near our gathering systems and our low operating costs and high on-line efficiency allow us to be extremely competitive when pursuing new business. Our midstream operations are expected to provide meaningful cash flow for expansion of our growth projects in 2003, given maintenance capital expenditures of approximately $11 million.

We were able to meet our reserve and production growth objectives in



**Western is focused on becoming a premier developer of natural gas in the resource rich Rocky Mountain West.**

2002 while further strengthening our balance sheet. We reduced our debt to capitalization ratio to 43 percent and retired the remainder of our $2.28 preferred stock. Our plan is to spend $182 million in 2003, 85 percent of which is allocated for the Rocky Mountain region. We plan to spend approximately $75 million for exploration and production activities and $58 million for gathering and processing operations, in addition to our recent $37 million acquisition of Wyoming gathering assets. Our strong balance sheet provides ample room for additional upstream or midstream acquisitions.

Western's Board of Directors and management team has formally adopted corporate governance requirements in compliance with the Sarbanes-Oxley Act and guidelines set forth by the New York Stock Exchange and the Securities and Exchange Commission. Consistent with past practices, we strive to provide our shareholders with an accurate reporting of Company business based on compliance with internal control processes, Company policies and all applicable laws and regulations.

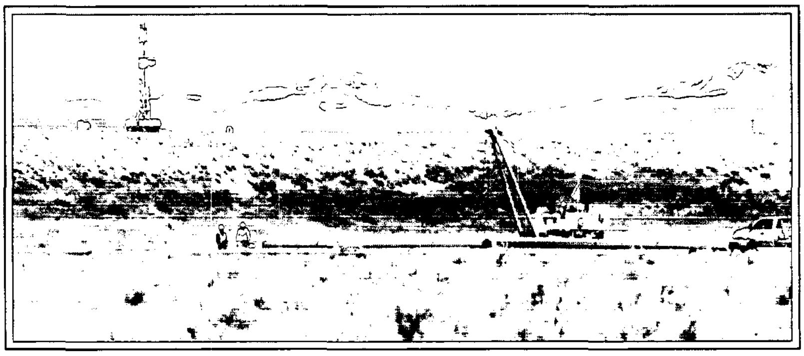
Western Gas employees bring a wide diversity of talent, a wealth of experience and an abundance of enthusiasm to the Company. Their efforts have established one of the largest positions in two of the most active onshore basins in the United States. Western's expertise in gathering, transportation and marketing helps us to successfully manage two of the primary issues that producers in the Rockies face—takeaway capacity and pricing.

In summary, we believe few companies have as long-term, low-risk, high-return drilling inventory under lease as Western. We intend to live up to our name as we focus on becoming a premier developer of natural gas in the resource rich Rocky Mountain West. Our outstanding human, financial and physical resources will deliver increasing value for our shareholders in the coming years. We thank you for your continued support.

Sincerely,

Peter A. Dea

**Peter A. Dea**
President and Chief Executive Officer



Pinedale Anticline

# ★ Powder River Basin Coal Bed Methane ★

**Nearly four billion cubic feet per day of coal bed methane is produced in the United States. Approximately 25 percent of it is coming from the Powder River Basin.**

The Durham Ranch is one example of how we and our co-developer work with landowners to ensure that our operations are mutually beneficial and have minimal impact to their property.

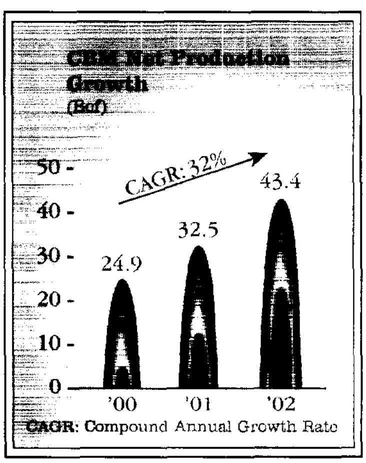
# Western experienced double-digit net production growth from the CBM play for the fifth straight year in 2002.

Western has established itself as one of the primary leaders in the production, gathering and transportation of Powder River Basin coal bed methane (CBM). We are one of the largest acreage holders and producers in this exciting natural gas play with over 515,000 net acres under lease and over 120 MMcfd of net production. Since the majority of this play has yet to be developed, the next decade will see substantial activity. In fact, outside sources indicate that up to 75 percent of the growth in CBM production in the United States could occur in this region. Western Gas is extremely well positioned to add value as the play matures.

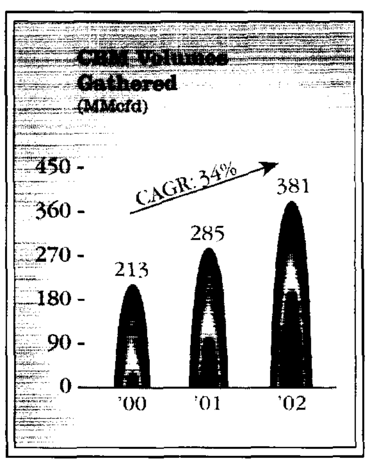
A new Department of Energy study has concluded that 29 Tcf of CBM in the Powder River Basin could be economically produced utilizing water disposal methods currently used by Western and as proposed by the pending Environmental Impact Statement (EIS). The new EIS, which is nearing a final Record of Decision (ROD), will allow industry to drill up to 39,000 new CBM wells in the Powder River Basin.

As of November 2002, over 10,000 CBM wells drilled by industry were producing approximately one Bcf from the Wyodak, Big George and related coals. Western has participated, with our 50 percent working interest, in over 3,700 gross wells in this low-cost, low-risk development. However, we are still early in the development phase. We added 64 Bcf of new reserves in the CBM play in 2002, net of revisions. The revisions were related to more conservative interpretation of the directives from the Securities and Exchange Commission (SEC), the under performing Hoe Creek area, and pressure draw down and related drainage in certain areas. Reserves related to the SEC directives will likely be booked in later years as drilling and dewatering proceed. Our proved reserves in the CBM play totaled 414 Bcf at year-end 2002.

Western experienced double-digit net production growth from the CBM play for the fifth straight year in 2002, with an increase of 33 percent from 2001 to an average of 118 MMcfd net. We participated in 909 gross wells in 2002 and experienced a 98 percent success rate. We plan to drill 845 gross wells during 2003.



CAGR: Compound Annual Growth Rate

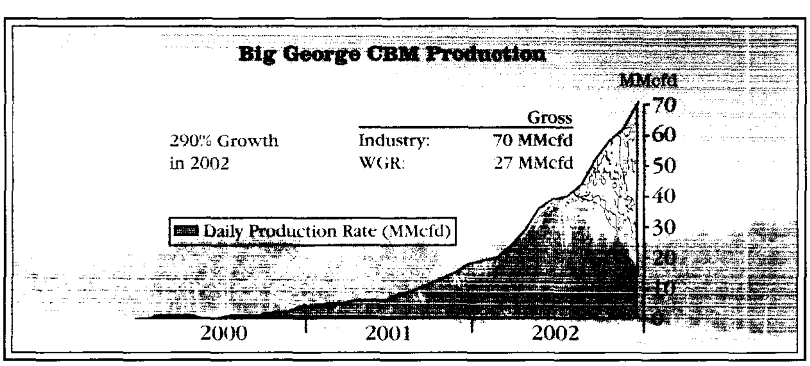


Powder River Basin

We anticipate increasing net production five to ten percent compared to 2002 as we transition from the relatively mature Wyodak coal on the eastern side of the Basin to the more prolific Big George coal to the west. The 2003 drilling program and related production are partially dependent on the timing of the EIS and subsequent receipt of drilling and water discharge permits. We will be laying the groundwork in 2003 for accelerating production growth in subsequent years. Our long-term drilling inventory of low-risk, low-cost, high rate of return wells in this exciting natural gas play should provide steady income for several years.

To date, approximately 88 percent of our drilling activity has occurred in the shallower Wyodak coal seams. However, approximately 65 percent of our highly prospective net acre position is on federal lands, the majority of which lies over the deeper and thicker Big George coals to the west. The completion of the EIS will allow us to substantially increase our activity in the Big George coal. Approximately 50 percent of our 2003 drilling program will target this coal. We believe individual well reserves and rates of the Big George coal will exceed those of the Wyodak due to greater thickness, higher gas content and higher pressure. The Big George will take an estimated twelve to twenty-four months to dewater versus six to nine months for a typical Wyodak well.

We have completed 425 wells in 12 pilot or development areas in the Big George coal through 2002. Gross production from our All Night Creek development has increased over 300 percent from January 2002 to 24 MMcfd as of February 2003. Two additional pilots were producing approximately 3.5 MMcfd of CBM volumes. The Big George was producing approximately 70 MMcfd industry-wide from pilot or development areas spanning 40 miles. This early success clearly supports the expected highly productive nature of the Big George coals, which could contain up to twice the per well reserves as the Wyodak coals. We have booked 49 Bcf of reserves as of year-end 2002 in the Big George coal, and have approximately 1.5 Tcf of unrisked probable and possible reserves in the high-potential Big George and Wall coal seam acreage.




**Early production growth in the Big George coal has mirrored that of the successful Wyodak coal.**

**Our integrated upstream and midstream strategy of natural gas development has proved very successful in the Powder River Basin CBM play.**

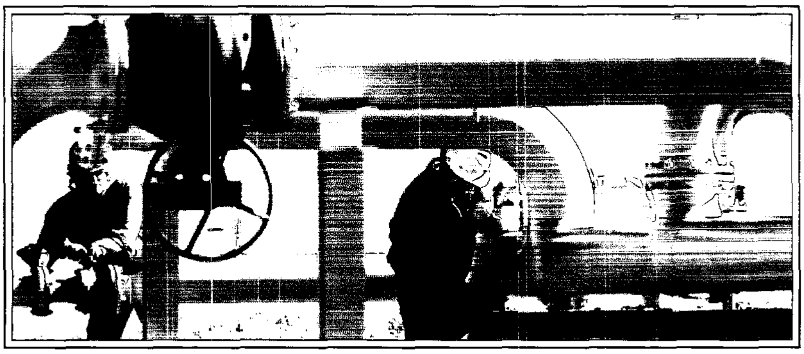
An additional 400 Bcf of unrisked probable and possible reserves underlie our leasehold in the Wyodak and other related coals, including the Werner, Gates, Anderson and Canyon coal seams.

Our integrated upstream and midstream strategy of natural gas development has proved very successful in the Powder River Basin CBM play, allowing us to control our own destiny and add value for our shareholders. We are the largest gatherer, compressor and transporter of Powder River Basin CBM due to our long established position as a midstream operator in this region and aggressive pursuit of new business.

CBM gathering volumes from our own production and third-party producers increased 33 percent in 2002 and averaged 381 MMcfd. Our wholly owned MIGC pipeline transported 135 MMcfd of CBM volumes in addition to 47 MMcfd of conventional gas. The 13-percent owned and operated Fort Union gathering pipeline, which also moves equity and third-party gas to the southern end of the Basin, gathered 453 MMcfd of gas, a 47 percent increase compared to 2001.

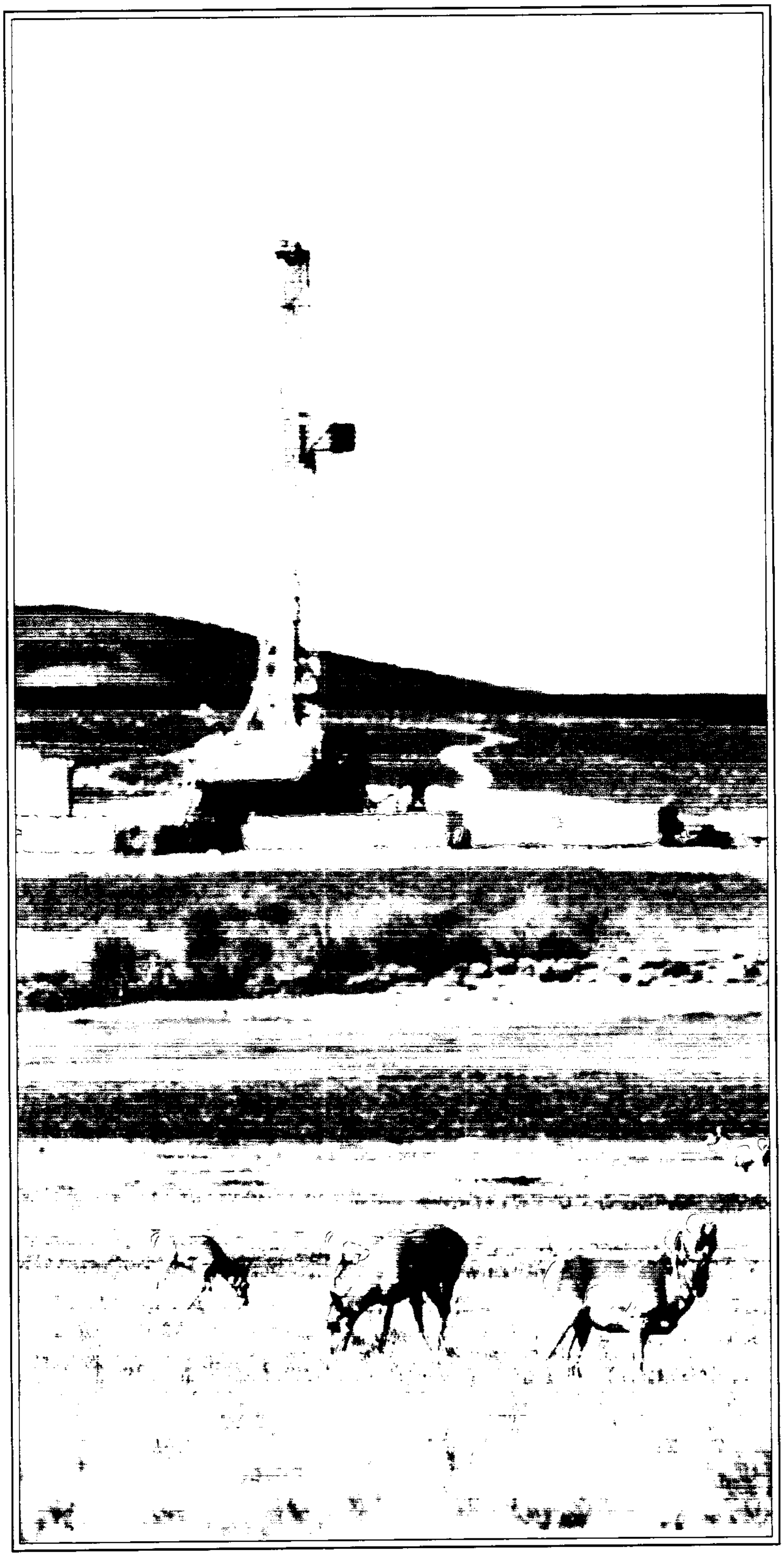
Our knowledge of natural gas markets and transportation in the Rockies and other areas has allowed us to successfully manage the commodity price risk common to this region. Nearly half of our equity gas receives Mid-Continent prices, less transportation costs, due to our firm transportation positions on major interstate pipelines from Wyoming to Mid-Continent markets.

The Powder River Basin CBM development is truly one of the premier natural gas success stories of the last 10 years. It represents one of the largest natural gas resources in the United States and is indicative of the enormous potential of the Rocky Mountain West. Western Gas Resources is well positioned in all facets of this important resource to help meet our nation's energy needs.



Big George CBM Compression,
All Night Creek Unit

# ☆ Greater Green River Basin ☆



**Ten years ago, the Jonah Field and Pinedale Anticline developments in the Green River Basin were largely undiscovered. Today, these natural gas fields collectively produce approximately one Bcf per day of natural gas as a result of new drilling and fracturing technology and increased infrastructure.**

Drilling activity is carefully controlled in the Pinedale Anticline area to minimize disruption to wildlife habitats.

## We experienced a 100 percent success rate on the Pinedale Anticline, having participated in 26 gross wells.

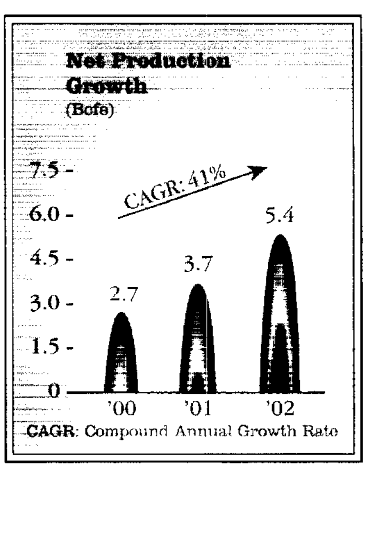
The Pinedale Anticline and Jonah Field area of the Greater Green River Basin in southwest Wyoming has emerged as one of the most prolific natural gas developments in the United States. Western Gas has an approximate 11-percent working interest across the majority of the Pinedale Anticline and in three sections in the Jonah Field.

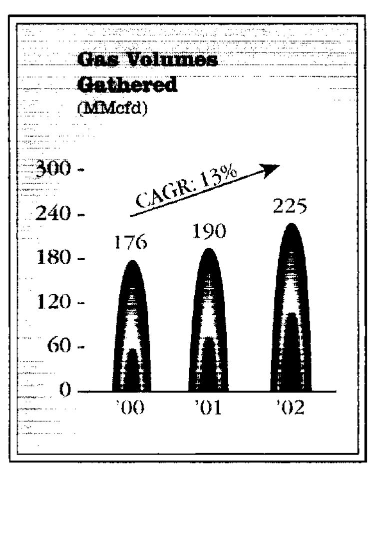
Our significant midstream presence in the area complements our growing production. Our assets include three processing plants and 790 miles of gathering systems. We completed two phases of the Rendezvous gathering system in 2002 to gather gas from the expanding Pinedale Anticline and deliver our share to the Granger facility. We will be connecting our recently acquired gathering systems in the Washakie Basin to our Red Desert facility on the eastern side of the Green River Basin. This will provide exposure to gathering and production opportunities in this developing area.

Western leveraged its asset base and knowledge of the Basin to acquire a 32,000 net acre position in the Pinedale Anticline area. We participated in 26 gross wells on the anticline in 2002 and experienced a 100 percent success rate. We added 96 Bcf of new reserves, including 18 Bcf from 40-acre downspacing, an increase of 133 percent from 2001. The cost to drill and complete a Pinedale well averaged $4 million in 2002 with average per well reserves of six Bcf. Future wells on the anticline will be drilled on 40-acre spacing and select wells will target the deeper Mesaverde sands in addition to the Lance formation. The Mesaverde sands add incremental reserves of two Bcf per well. We plan to participate in 32 wells with our partners in 2003. Western could have exposure to an additional 500 gross well locations representing a 14-year drilling program at the current pace.

Western also has approximately 177,000 net acres and 13 Bcf of proven reserves in the Sand Wash Basin in northwest Colorado, where we drilled two successful wells and spud a third well in 2002. Six wells and three workovers are planned for this area in 2003 to expand the limits of the field.

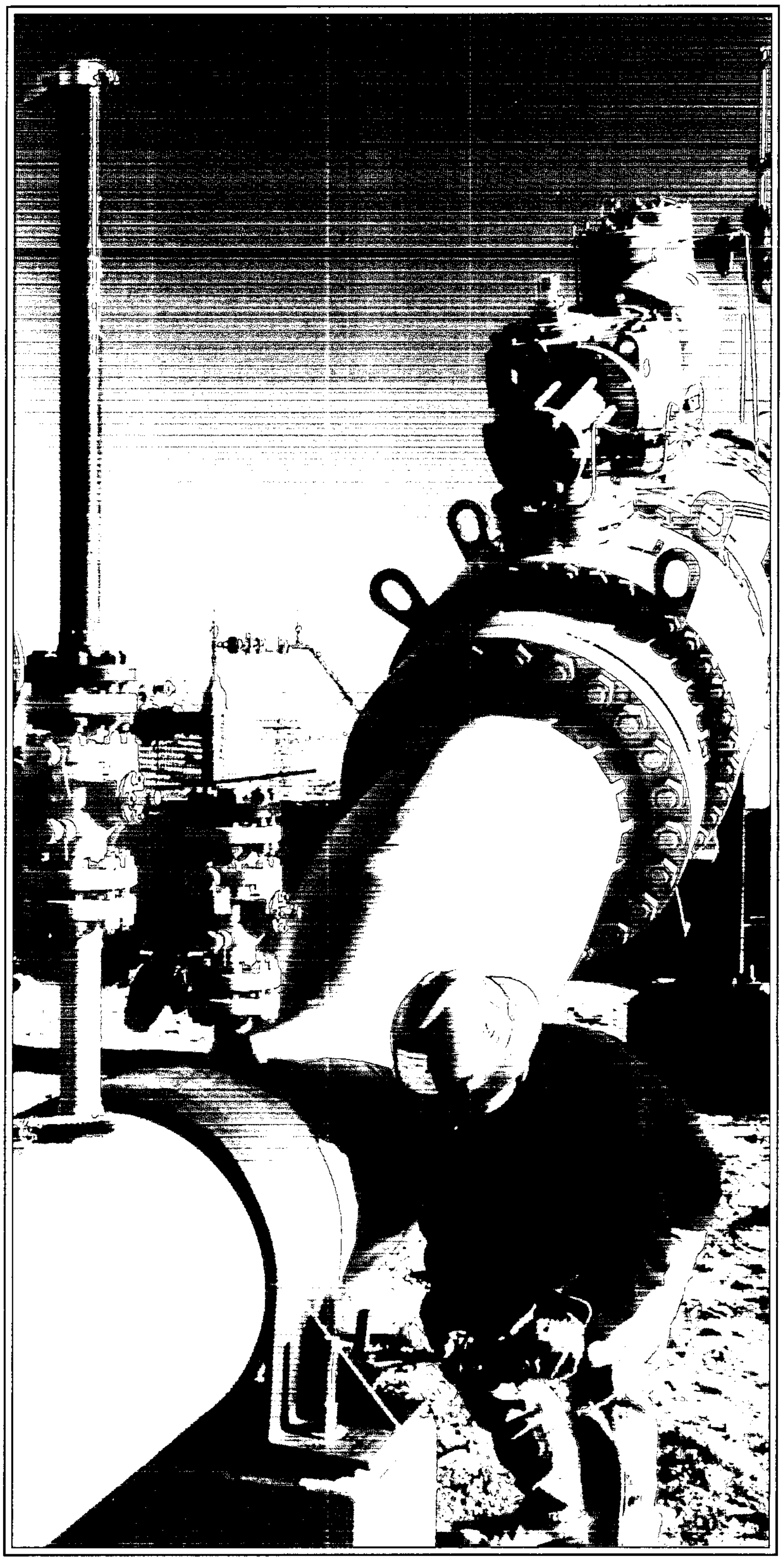
Net gas production from the Greater Green River Basin area, including the Sand Wash Basin, increased 47 percent to an average of 14.9 MMcfed in 2002. In 2003, we expect net production from these areas to average 20 MMcfed, an increase of 34 percent from 2002.



# ★ MIDSTREAM ASSETS ★

**Western's expertise and assets in natural gas gathering, processing, transportation and marketing provide Western with strategic competitive advantages.**



The new Rendezvous gathering system in southwest Wyoming can gather up to 275 MMcfd of natural gas.

**In 2002, operating profit of $93 million from our gathering and processing business coupled with low maintenance costs of $7.4 million helped fund our growth projects.**

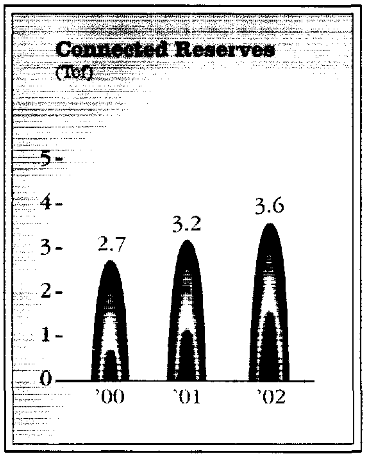
Western's gathering and processing operations are located in some of the most actively drilled gas and oil producing basins in the United States. Our midstream assets in West Texas, northern Oklahoma and the San Juan Basin of northwestern New Mexico and southwestern Utah complement our integrated upstream and midstream operations in the Powder River and Green River Basins of Wyoming. In each area, our technical expertise, low service costs and modernization upgrades provide a competitive advantage to capture third-party gas supplies through acquisitions and new reserve dedications.

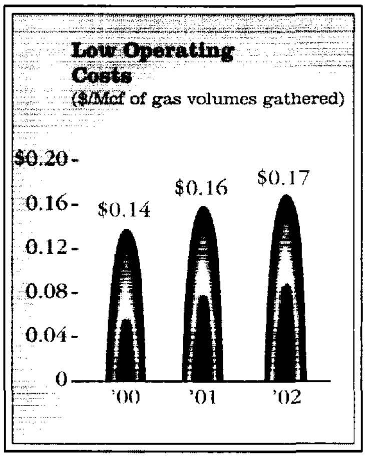
In 2002, operating profit of $93 million from gathering and processing coupled with low maintenance costs of $7.4 million helped fund our growth projects in the upstream and midstream businesses. We hooked up 245 new wells in West Texas and Oklahoma in 2002 as third-party producers developed new gas supplies within these active basins. We are also reaping the rewards from our modernization upgrades made in the last few years. One such investment in West Texas saved us approximately $4 million in reduced fuel consumption and lower maintenance and manpower costs in 2002. Savings could increase substantially in 2003 based on higher gas prices and resulting fuel expenses. Our midstream business operating costs averaged $0.17 per Mcf of gathering volumes in 2002, amongst the lowest in industry.

In support of our focus on the Rocky Mountain region, we sold our Toca processing facility in the Gulf Coast region for $32 million in 2002 and purchased several Wyoming gathering assets in early 2003 for $37 million. These new assets include 550 miles of gathering lines with approximately 140 MMcfd of gathering volumes in three Wyoming gas basins. The acquisition adds a solid base of long-term, fee-based gathering contracts and positions us for future opportunities in the Washakie and Wind River Basins.

New well connections in our core areas and the new Wyoming assets should result in a 20 percent increase in gas gathering volumes in 2003.

Overall, the 3.6 Tcf of proved gas reserves dedicated to our systems combined with attractive profit margins will continue to provide stable long-term returns to our shareholders from the focused midstream assets.



# ★ EXPLORATION ★

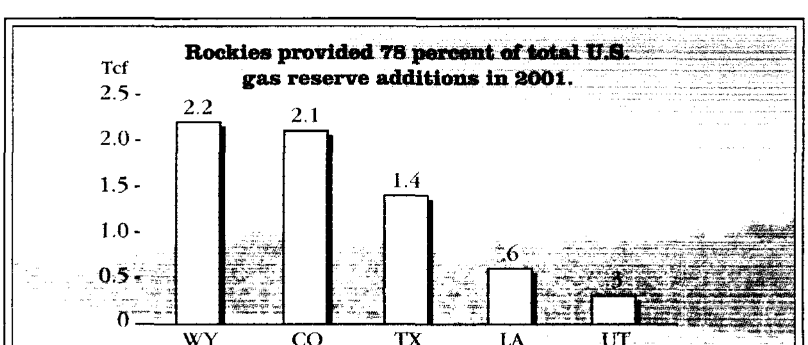
## Our newly formed exploration and acquisition team will identify and evaluate new company building projects in the Rocky Mountain region.

The largest untapped onshore natural gas resource base in the United States lies in the Rocky Mountain region according to most sources. In order to meet the expected demand for clean energy over the next ten years, we as industry must find and deliver new gas supplies to the marketplace. The Rockies region will be a leading contributor in this effort. Reserve and production data has established a strong track record and trend for the Rockies. In 2001, 78 percent of the natural gas reserve additions in the entire United States came from Wyoming, Colorado and Utah. Since the 1970's, gas production increased over 500 percent in the Rockies while declining 20 to 30 percent in more mature regions.

Our newly formed exploration and acquisition team will identify and evaluate new company building projects in the Rocky Mountain region. New opportunities may include in-house and third-party generated exploratory prospects and the acquisition of producing properties of various sizes. The multi-disciplined team will leverage off their many years of experience and our internal expertise in unconventional gas resources, particularly coal bed methane and tight gas sands.

The exploration team has completed a basin ranking analysis that has identified the top Rocky Mountain basins for Western Gas Resources. We will evaluate outside generated opportunities in those and other gas prone basins in the Rockies and in areas where we can apply our expertise in unconventional resources. Additionally, we will look for added value by identifying opportunities to integrate our midstream operations. In fact, our expertise in the design, construction and operation of gathering systems may provide Western with a unique competitive advantage to attract new company building exploration and production projects. Such has been the case in the past.

Overall, we are looking for high-return projects that offer long-term, low-risk drilling inventories that would have a sustaining and meaningful impact on the Company.



# Environmental & Safety

Pinedale Anticline

Western is dedicated to preserving the environment where we operate and in the communities where we live and maintaining our reputation as a good neighbor. To demonstrate our commitment, we recently developed new environmental and safety policies. These policies describe Western's commitment to preserving the environment in all of our activities, as well as our dedication to safety. Our employees are aware of their responsibility to perform their duties in accordance with all applicable environmental laws and internal policies, and they are equipped with the necessary resources to meet those expectations.

In the past two years, Western has spent over $29 million to replace old inefficient compressors with new higher efficiency equipment in West Texas. These improvements have reduced emissions by several thousand tons per year and significantly reduced the amount of fuel required to compress the same volume of gas.

In the Powder River Basin, other examples of our proactive approach to the environment include directing fresh potable water associated with coal bed methane wells to ponds for beneficial use by ranchers and wildlife such as antelope, deer and waterfowl, and minimizing the impact of our operations by building fewer roads and reducing the size of drilling locations.

We regularly conduct environmental and safety assessments of existing operations. We voluntarily perform clean-up activities at sites with both ongoing and discontinued operations. Western periodically reviews its existing environmental permits in light of better technology and more accurate prediction methods and subsequently makes the necessary changes. Many of these changes result in fewer emissions, as well as an economic benefit in the form of increased fuel efficiency.

In the community, we are corporate sponsors of several activities that benefit the environment. Our contribution of funds and our employees' voluntary contribution of their time help to restore wetlands, improve trails, plant trees and preserve grasslands.

Americans have acknowledged the preference for natural gas as their clean-burning fuel of choice. We at Western are doing our part to supply clean energy to America with our focus on developing natural gas and doing so in an environmentally sound manner.

**Western is dedicated to preserving the environment where we operate and in the communities where we live.**

# ★ Board of Directors ★

BRION WISE, 57 (▲)
Chairman of the Board
Director since 1987

WALTER STONEHOCKER, 78 (▲, ●)
Vice Chairman
Retired Senior Vice President
Director since 1987

PETER DEA, 49
Chief Executive Officer & President
Director since 2001

LANNY OUTLAW, 67
Retired Chief Executive Officer & President
Director since 1999

DEAN PHILLIPS, 71 (■, ✻)
President
Heetco, Inc.
Director since 1987

JOSEPH REID, 74 (●, ■, ✻)
Independent Oil & Gas Consultant
Retired Chief Executive Officer & President
Meridian Oil Company
Director since 1994

RICHARD ROBINSON, 54
Partner
Lentz, Evans and King, P.C.
Director since 1987

BILL SANDERSON, 73 (▲, ●, ✻)
Retired President & Chief Operating Officer
Director since 1987

WARD SAUVAGE, 77 (▲, ■)
President
Sauvage Gas Company
Director since 1987

JAMES SENTY, 67 (●, ■, ✻)
Chairman of the Board
The Park Bank
Director since 1987

Member Executive Committee ▲
Member Audit Committee ●
Member Compensation Committee ■
Member Nominating & Governance Committee ✻

# ★ Officers ★

PETER DEA, 49
President & Chief Executive Officer

BILL KRYSIAK, 42
Executive Vice President & Chief Financial Officer

JOHN WALTER, 57
Executive Vice President & General Counsel

JOHN CHANDLER, 46
Executive Vice President, Upstream & Marketing

ED AABAK, 51
Executive Vice President, Midstream

BRIAN JEFFRIES, 45
Vice President, Marketing

BURT JONES, 43
Vice President, Business Development

JEFF JONES, 49
Vice President, Production

DAVE KEANINI, 42
Vice President, Engineering, Environmental & Safety

VANCE BLALOCK, 49
Vice President & Treasurer

Western's officer team pictured at new corporate headquarters in downtown Denver.
(L to R standing) Dave Keanini, Jeff Jones, Bill Krysiak, John Chandler, Brian Jeffries, Ed Aabak, Burt Jones
(L to R seated) John Walter, Peter Dea, Vance Blalock.

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

# FORM 10-K

(Mark One)

[X] Annual report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2002 or

[ ] Transition report pursuant to section 13 or 15(d) of the Securities Exchange Act of 1934 for the transition period from ________________ to ________________

Commission file number 1-10389

# WESTERN GAS RESOURCES, INC.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Delaware | 84-1127613 |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |
| 1099 18th Street, Suite 1200, Denver, Colorado | 80202 |
| (Address of principal executive offices) | (Zip Code) |

(303) 452-5603
Registrant's telephone number, including area code

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

| Title of each class | Name of exchange on which registered |
|---|---|
| Common Stock, $0.10 par value | New York Stock Exchange |
| $2.625 Cumulative Convertible Preferred Stock, $0.10 par value | New York Stock Exchange |

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

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

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

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

The aggregate market value of voting common stock held by non-affiliates of the registrant on June 30, 2002 was $1,234,329,292.

The number of shares outstanding of the only class of the registrant's common stock, as of March 3, 2003, was 33,099,577.

DOCUMENTS INCORPORATED BY REFERENCE

Information required by Part III of this Report (Items 10, 11, 12 and 13) is incorporated by reference from the registrant's proxy statement to be filed pursuant to Regulation 14A with respect to the annual meeting of stockholders scheduled to be held on May 16, 2003.

Western Gas Resources, Inc.
Form 10-K
Table of Contents

PART I

## ITEMS 1 AND 2. BUSINESS AND PROPERTIES

*The terms Western, we, us and our as used in this Form 10-K refer to Western Gas Resources, Inc. and its subsidiaries as a consolidated entity, except where it is clear that these terms mean only Western Gas Resources, Inc.*

### *General*

Western explores for, develops and produces, gathers, processes and treats, transports and markets natural gas and natural gas liquids, NGLs. In our upstream operations, we explore for, develop and produce natural gas reserves primarily in the Rocky Mountain region. In our midstream operations, we design, construct, own and operate natural gas gathering, processing and treating facilities; we own and operate regulated transportation facilities; and we offer marketing services in order to provide our customers with a broad range of services from the wellhead to the sales delivery point. Our midstream operations are conducted in major gas-producing basins in the Rocky Mountain, Mid-Continent and West Texas regions of the United States.

Our operations are conducted through the following four business segments:

- *Upstream*—We explore for, develop and produce natural gas reserves independently and to enhance and support our existing gathering and processing operations. We sell the natural gas that we produce to third parties. Our producing properties are primarily located in the Powder River and Green River Basins of Wyoming. Our strategy is to seek new gas prospects in the Rocky Mountain region by utilizing our expertise in coal bed methane and tight-gas sand development. The development of new gas prospects may provide additional opportunities for our other business segments.

- *Gathering, Processing and Treating*—Our core operations are in well-established areas such as the Permian, Anadarko, Powder River and Green River Basins. We connect natural gas from gas and oil wells to our gathering systems for delivery to our processing or treating plants. At our plants we process natural gas to extract NGLs and we treat natural gas in order to meet pipeline specifications. We provide these services to major oil and gas companies, to independent producers of various sizes and for our own production.

- *Marketing*—We buy and sell natural gas and NGLs in the wholesale market in the United States and in Canada. Our gas marketing is an outgrowth of our gas processing and upstream activities and is directed towards selling gas produced at our plants or from our wells in an effort to ensure efficient operations and to maximize returns. We provide transportation, scheduling, peaking and other services to our customers. Our customers for these services include utilities, local distribution companies, industrial end-users and other energy marketers. We are also an active marketer of third-party natural gas throughout the United States.

- *Transportation*— In the Powder River Basin, we own one interstate pipeline and one intrastate pipeline which transport natural gas for producers and energy marketers under fee schedules regulated by state or federal agencies.

Historically, we have derived over 95% of our revenues from the sale of gas and NGLs. Our revenues by type of operation are as follows (dollars in thousands):

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2002 | % | 2001 | % | 2000 | % |
| Sale of gas | $ 2,123,468 | 85.3 | $ 2,849,097 | 85.0 | $ 2,628,052 | 80.1 |
| Sale of natural gas liquids | 309,697 | 12.4 | 424,082 | 12.6 | 590,932 | 18.0 |
| Processing and transportation revenue | 65,601 | 2.6 | 55,398 | 1.6 | 53,156 | 1.6 |
| Non-cash change in fair value of derivatives | (13,788) | (0.5) | 19,906 | 0.6 | - | - |
| Other | 4,720 | 0.2 | 4,679 | 0.2 | 7,951 | 0.3 |
| | $ 2,489,698 | 100.0 | $ 3,353,162 | 100.0 | $ 3,280,091 | 100.0 |

### *Business Strategy*

Maximizing the value of our existing core assets and locating new growth projects in the Rocky Mountain region are the focal points of our business strategy. Our core assets are our fully integrated upstream and midstream properties in the Powder River and Green River Basins in Wyoming and our midstream operations in west Texas and Oklahoma. Since 2001, our long-term business plan has been to increase shareholder value by: (i) doubling proven reserves and equity production of natural gas from the level at December 31, 2001 over a three to five year period; (ii) meeting or exceeding throughput projections in our midstream operations; and (iii) optimizing annual returns.

*Double Proven Natural Gas Reserves and Equity Production of Natural Gas from the level at December 31, 2001 over a three to five year period.* In order to achieve this goal, we will focus on continued development of our leasehold positions in the Powder River Basin coal bed methane, or CBM, and development in the Green River and the Sand Wash Basins and actively seek to add another core natural gas development project. Overall, we have acquired drilling rights on approximately 820,000 net acres in these and other Rocky Mountain basins. At December 31, 2002, we had proved developed and undeveloped reserves of approximately 588 billion cubic feet equivalent, Bcfe, on a portion of this acreage position. In total this represents an increase of approximately 24% in our proved reserves from December 31, 2001. Reserve life, determined by dividing our proved reserves by our 2002 production, is over 12 years. During 2002 our production of natural gas as compared to 2001 increased by 33% to 48.9 Bcfe and we replaced 332% of our 2002 production. All of our 2002 reserve and production growth was achieved on our existing acreage. In the Powder River Basin, future growth potential lies in over 10,000 well locations in the Big George, Wyodak and related coals if the play is fully successful. In the Green River Basin, our reserve potential is in the development of 80-acre and 40-acre locations on our leasehold on the Pinedale Anticline, which target sandstone reservoirs in the Lance and Mesa Verde formations.

We are also actively seeking to add another core project that is focused on Rocky Mountain natural gas. We will utilize our expertise in exploration and low-risk development of tight-gas sands and coal bed methane plays to evaluate acquisitions of either additional leaseholds, proven and undeveloped reserves or companies with operations focused in this area. To further enhance our ability to accomplish this goal, in 2002 we added to the staff of experienced individuals in our exploration and production department, including additional geologists and a reservoir engineer. These individuals bring a new level of expertise in identifying opportunities in the Rocky Mountain region and are actively evaluating several prospects. The addition of another core project will ideally result in new investment opportunities in our midstream operations.

*Meet or Exceed Throughput Projections in our Midstream Operations.* To achieve this goal, we must continue our efforts to add to natural gas throughput levels through new well connections, expansion or acquisition of gathering or processing systems and the consolidation of existing facilities. We also seek growth opportunities for gathering and processing through our development of new gas reserves. These operations provide us with steady throughput volumes and significant cash flow that we can in turn reinvest in new growth opportunities in either our upstream or midstream businesses. Over the last five years, the throughput volume at our gathering and processing facilities has averaged 1.2 Bcf per day and operating income contributed by these facilities has averaged $103.2 million per year.

Our gathering and processing operations are located in some of the most actively drilled oil and gas producing basins in the United States. We enter into agreements under which we gather, process or treat natural gas produced on acreage dedicated to Western by third parties or produced by Western. We contract for production from newly developed acreage in order to replace declines in existing reserves or increase reserves that are dedicated for gathering, processing or treating at our facilities. Historically, while certain individual plants have experienced declines in dedicated reserves, we have been successful in connecting additional reserves to more than offset the natural declines. At December 31, 2002, the estimated reserves connected to our midstream facilities totaled 3.6 Tcf. This includes our estimate of future third-party production and our proven reserves. The estimated third-party reserves connected to our facilities are based upon our interpretation of publicly available well and production information and are not the result of audited reserve reports prepared for us. In 2002, including the reserves developed by us and associated with our partnerships, and excluding the reserves and production associated with the facilities sold during this period, we connected new reserves to our facilities to replace approximately 205% of throughput. During 2002, we spent approximately $52.5 million on additional well connections and compression and gathering system expansions.

We will also evaluate investments in expansions or acquisitions of assets that complement and extend our core natural gas gathering, processing, treating and marketing businesses and new growth projects in the Rocky Mountain region. On January 31, 2003, we acquired 18 gathering systems in Wyoming, primarily located in the Green River Basin with smaller operations in the Powder River and Wind River Basins, for a total of $37.1 million. These systems are comprised of a total of 550 miles of gathering lines and, at January 31, 2003, were gathering a total of 139 MMcf per day. The Green River Basin is one of our core operating areas and these systems will be consolidated into our existing operations in this area. The Wind River Basin systems provide us with the opportunity to expand our gathering and processing activities into an area in which we have not previously operated. The remaining systems will be evaluated for consolidation opportunities or divestiture.

*Optimize Annual Returns.* To optimize our annual returns, we will focus our efforts in our primary operating areas in the Powder River and Green River Basins in Wyoming, the Anadarko Basin in Oklahoma and the Permian Basin in west Texas. We review the economic performance and growth opportunities of each of our assets to ensure that a satisfactory rate of return is achievable. If an asset is not generating targeted returns or is outside our core operating areas, we explore various options, such as integration with other Western-owned facilities or consolidation with third-party-owned facilities, dismantlement, asset trades or sale. In September 2002, we sold our Toca processing facility in Louisiana for $32.2 million, subject to accounting adjustments. This facility, while achieving a satisfactory return, was not located in one of our primary operating areas and did not have significant growth opportunities. The sale of this asset allows us to concentrate our capital investment and manpower on our core operations. Consolidations and joint ventures allow us to increase the throughput of one facility while reducing the capital invested in, and the operating costs of, the consolidated assets. For example, the formation of Rendezvous Gas Services, L.L.C. with Questar Gas Management Company in 2001 increases gas available for processing at our Granger gas processing facility in southwest Wyoming and reduces our capital investment requirements.

We routinely evaluate our business for methods to reduce our operating and administrative costs, including the implementation of automation and information technology. Replacing and upgrading field equipment allows us to minimize maintenance costs, fuel consumption and field operating costs. Over the last several years, we invested $29.0 million to replace older compression units at our Midkiff/Benedum facility with fuel-efficient equipment. This upgrade has resulted in reduced emissions and a decrease in our fuel consumption and has accordingly increased the natural gas available for sale and our ability to attract additional volumes to our system.

This section, as well as other sections in this Form 10-K, contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, which can be identified by the use of forward-looking terminology, such as "may," "intend," "will," "expect," "anticipate," "estimate," or "continue" or the negative thereof or other variations thereon or comparable terminology. This Form 10-K contains forward-looking statements regarding the expansion of our gathering operations, our project development schedules, our budgeted capital expenditures, success of our drilling activities, our marketing plans and anticipated volumes through our facilities and from production activities that involve a number of risks and uncertainties, including the composition of gas to be treated, drilling schedules, the success of the producers with acreage dedicated to our facilities, and continuing litigation and other disputes with our co-developer in the Powder River Basin. In addition to the important factors referred to herein, numerous other factors affecting our business generally and in the markets for gas and NGLs in which we participate, could cause actual results to differ materially from our projections in this Form 10-K. See further discussion in "Financial Statements and Supplementary Data - Notes to Consolidated Financial Statements - Note 2 - Summary of Significant Accounting Policies - Use of Estimates and Significant Risks."

Western Gas Resources, Inc. was incorporated in Delaware in 1989. On March 18, 2003, we relocated our principal offices to Denver Place, 1099 18th Street, Suite 1200, Denver, Colorado 80202. Our telephone number is (303) 452-5603.

Our website address is http://www.westerngas .com We make available free of charge through our website our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission, or SEC.

*2003 Capital Budget*

In order to maintain a strong balance sheet, our general goal is to limit our capital expenditures, excluding acquisitions, in any single year to 110% of the projected cash flow generated by our operations for that year. In some years, however, we expect that we will exceed this limitation based on the growth and acquisition opportunities available to us. In 2003, we anticipate capital expenditures of approximately $182.3 million. We expect that the Rocky Mountain region will utilize 85% or $155.2 million of the 2003 budget.

The majority of our capital expenditures will be in the Powder River Basin CBM development and in the Greater Green River Basin. In the Powder River Basin CBM development, we plan to invest approximately $68.0 million, or 37% of our total capital program. Of this amount, approximately $55.2 million will be spent on our share of drilling 845 gross wells and for production equipment and undeveloped acreage and $12.8 million for gathering lines and installation of additional compression units.

In the Greater Green River Basin we expect to invest approximately $82.3 million, or 45% of the total 2003 capital expenditure program. We plan to spend approximately $18.4 million to participate in approximately 41 gross wells, including three well workovers, the majority of which are in the rapidly developing Pinedale Anticline area and $26.8 million to expand gathering and compression services. In January 2003, we spent a total of $37.1 million for the acquisition of 18 gathering systems, the largest systems of which are located in the Greater Green River Basin.

The remaining $32.0 million of our 2003 capital spending program is expected to be spent as follows: $19.9 million for midstream operations in other areas, $7.8 million for capitalized interest and overhead and $4.3 million for administrative expenditures. Overall, we expect to spend $11.4 million on maintenance and upgrade projects for existing midstream facilities. Due to drilling and regulatory uncertainties that are beyond our control, we can make no assurance that our capital budget for 2003 will not change.

*Upstream Operations*

A vital aspect of our long-term business plan is to double proven reserves and equity production of natural gas from the level at December 31, 2001over a three to five year period. In order to achieve this goal, we will focus on continued development of our leasehold positions in the Powder River coal bed methane development, the Green River Basin and the Sand Wash Basin. Each of our existing upstream projects are fully integrated with our midstream operations. In other words, we provide the gathering, compression, processing, marketing or transportation services for both our own production and for third-party operators.

*Powder River Basin Coal Bed Methane.* We continue to develop our Powder River Basin coal bed methane reserves and expand the associated gathering system in northeast Wyoming. The Powder River Basin coal bed methane area is currently one of the largest on-shore plays for the development of natural gas in the United States. Within this area, together with our co-developer, in 2002, we were the largest producer of natural gas. In addition, we are the largest gatherer of natural gas and, through our MIGC pipeline, transport a significant volume of gas out of this basin.

At December 31, 2002, we held the drilling rights on approximately 515,000 net acres in this basin, and as of December 31, 2002, we had established proven developed and undeveloped reserves totaling 414 Bcfe on a portion of this acreage, 52% of which are proven and developed. This represented an overall 5% increase in proven reserves as compared to December 31, 2001. In total, as a result of our drilling program, we added 169.1 Bcfe of proven reserves in this play in 2002. Partially offsetting these additions was production of 43.4 Bcfe during the year and downward revisions of existing reserves of 105 Bcfe. These downward revisions were the result of several factors including a more stringent interpretation of SEC proved reserve criteria, which resulted in a 23 Bcfe downward revision; pressure depletion caused by offset drainage and our own drilling in the older developed areas which resulted in a downward revision of 11 Bcfe; and new production and core data showing lower resource estimates for the Hoe Creek area and Lower Canyon coal, which resulted in a downward revision of 46 Bcfe. The remaining 25 Bcfe of revisions were in a number of areas and were caused by a number of factors including core data, 40-acre development drainage, well performance and offsetting pressure reduction indicating depletion of un-drilled locations.

The drilling operations in the Powder River Basin through December 31, 2002 have primarily focused on developing reserves in the Wyodak coal, which is located on the east side of the coal bed development. We participated in the drilling of 909 gross wells in 2002, of which 723 were drilled in the Wyodak coal and 186 were drilled in the Big George coal. We plan to participate in 845 gross wells in 2003, of which 441 are scheduled to be drilled in the Wyodak coal and 404 are scheduled to be drilled in the Big George coal. The average drilling and completion cost for our coal bed methane gas wells is approximately $90,000 to $120,000 per well with average reserves per successful well of approximately 275 MMcf. Our finding and development costs in this area in 2002, including reserve revisions, averaged approximately $0.31 per Mcf. The majority of future development will be concentrated on developing the Big George and other coal seams. Much of the Big George coal seam is deeper and thicker than the Wyodak coal. We expect that as wells are drilled and developed in the Big George coal, the gas reserves and production per well and the average drilling and completion cost per well will increase.

Our share of production from wells in which we own an interest has increased from an average of approximately 105 MMcfe per day in the month of December 2001 to 126 MMcfe per day, excluding prior period revisions, in the month of December 2002. We have experienced a 1.5% decline in production in the month of January 2003 to an average 124 MMcfe per day, excluding prior period adjustments. This decline is primarily due to operational and permitting delays, under-performance of wells in the Hoe Creek area and the timing of the Powder River Basin Oil & Gas Environmental Impact Statement, or EIS. We currently anticipate an average production rate of 132 net MMcfe per day from this area in December 2003.

As of December 31, 2002, we had participated in the drilling of approximately 3,800 wells drilled in the Powder River Basin CBM play. Of these, approximately 2,900 are producing gas wells; approximately 400 are in the process of being dewatered, which reduces pressure in the coals in order to release gas; and approximately 400 are waiting on connection to gathering systems. The remaining wells that have been drilled have produced all their recoverable reserves. During the first half of 2003, we anticipate that approximately 300 of the 400 wells awaiting connection to gathering systems will be connected and will be put into gas production. The remaining 100 wells will be connected to a gathering system once wider-scale development drilling in the area in which these wells are located commences.

Industry-wide, production from the Big George coal increased by 293% in 2002 and in early February 2003, production rates totaled approximately 70 MMcf per day from eight separate pilots. We are currently evaluating 11 pilot areas and one development area in the Big George. Through December 31, 2002, we have drilled approximately 425 gross wells in the Big George coal area. We have marketable production quantities in the All Night Creek, Pleasantville and Kingsbury areas. In early February 2003, these areas were producing a combined 27.5 gross MMcf per day. At December 31, 2002, we had proven reserves of 49 Bcfe in the Big George coal, primarily associated with the All Night Creek development area.

Future drilling on the majority of our federal acreage is contingent on completion of the EIS. The 30-day protest period for the final draft of the EIS ended on February 18, 2003. The Bureau of Land Management's Buffalo, Wyoming field office tentatively plans to issue the final Record of Decision by mid April 2003. That date could be delayed based on the quantity and nature of the protests received on the final EIS. A significant portion of the wells we plan to drill in 2003 would require federal permits to be issued pursuant to the completion of the EIS. We do not expect that any limit on our ability to drill during 2003 will affect the rate of our production until late in 2003. Based on our preliminary review of the final EIS, we expect that the cost and timing of drilling and operating on federal lands in the Powder River Basin may increase but do not expect that any increases will have a material adverse impact on our results of operations or financial position.

Additionally, the Wyoming Department of Environmental Quality, or DEQ, has revised some standards for surface water discharge that have allowed the issuance of most of the permits that apply to the Cheyenne and Belle Fourche drainage areas. The majority of wells on our acreage producing from the Wyodak formation drain into these areas. The Wyoming and Montana DEQ offices have reached agreement on procedures for discharging and monitoring water into the Powder River and other drainage areas, in which most of our undeveloped prospects are located. Although the Wyoming and Montana DEQ offices have reached this agreement, the Wyoming DEQ has begun to grant permits only on a limited basis to the Powder River drainage area when it can be demonstrated that none of the discharge water will reach the Powder River itself. Therefore, we can make no assurances that the conditions under which additional permits are granted will not impact the level of drilling or the cost and timing of the associated production.

On April 26, 2002, the Interior Board of Land Appeals, or IBLA, ruled that the BLM did not comply with the National Environmental Policy Act, or NEPA, prior to issuing three federal oil and gas leases held by an unaffiliated third party in the Powder River Basin. There has not been a final decision regarding the validity of the three leases. The IBLA has remanded the case to the Wyoming BLM State Director without specifying a remedy. The State Director could, among other things, require additional NEPA analysis to be done on these three leases. The EIS is currently being conducted basin wide. This study includes a NEPA analysis covering coal bed methane development. The unaffiliated leaseholder has filed for judicial review in federal district court in Wyoming. We do not have any interests in these leases nor have we received notice of any challenge to leases that we hold. We are continuing to monitor the development of the issue.

Our 2003 capital budget in the Powder River Basin coal bed development includes approximately $55.2 million for drilling costs, production equipment and lease acquisitions. During 2002, our capital expenditures in these activities totaled $51.9 million. Depending upon future drilling success, we may need to make additional capital expenditures or leasing commitments to continue expansion in this basin. In addition, due to regulatory uncertainties, which are beyond our control, we can make no assurance that we will incur this level of capital expenditure. Our co-developer in this area is also required to make similar capital commitments to continue the pace of the development as planned. During 2002, our co-developer in this area publicly disclosed that it had financial difficulties. We are currently unable to predict the impact, if any, of our co-developer's financial situation on the future pace of development in the Powder River Basin. Several disputes have arisen between our co-developer and us. These disputes are more fully described in Note 8 to the Consolidated Financial Statements

***Green River Basin.*** Our upstream assets in the Green River Basin of southwest Wyoming are located in the Jonah Field and Pinedale Anticline areas. As of December 31, 2002, we owned approximately 194,000 gross oil and gas leasehold acres, or approximately 32,000 net acres, in these areas. During 2002, we participated in 26 gross wells, or 4 net wells, in these areas, at a cost of $17.3 million and experienced a success rate of 100%. Our capital budget for 2003 in the Jonah Field and Pinedale

Anticline areas provides for expenditures of approximately $12.9 million for drilling costs and production equipment. Due to drilling and regulatory uncertainties, which are beyond our control, there can be no assurance that we will incur this level of capital expenditure. During 2003, we expect to participate in the drilling of 32 gross wells, or approximately 4 net wells on the Pinedale Anticline. The expected drilling and completion costs per gross well range from $3.0 million to $4.0 million and the average well depth in this area approximates 13,000 feet and has average gross reserves per successful well of approximately 4 Bcfe. Our average finding and development costs in 2002 were $0.47 per Mcfe, including new reserves attributable to 40-acre spacing. During December 2002, we produced an average of 19.2 MMcfe per day, net, from these areas. We had established proven developed and undeveloped reserves totaling 161 Bcfe at December 31, 2002. This represents a 133% increase as compared to December 31, 2001 in part due to a 18 Bcfe revision resulting from attributing reserves to all 40-acre proved undeveloped locations. There can be no assurance, however, as to the ultimate recovery of these reserves.

*Sand Wash Basin.* We continue to explore and develop our acreage position in the Sand Wash Basin in northwest Colorado. We own approximately 208,000 gross oil and gas leasehold acres, or approximately 177,000 net acres, in this basin. In December 2002, we were producing an average of 2.7 MMcf per day from this acreage. At December 31, 2002, we had established proven developed and undeveloped reserves totaling 13 Bcfe on a portion of this acreage. This represents a slight increase from the proved reserves at December 31, 2001. The majority of this acreage is in the exploration phase and will be evaluated in 2003 and subsequent years. Our capital budget in this area provides for expenditures of approximately $5.3 million during 2003 for our participation in the drilling of six gross developmental wells, or four net wells, and three workovers of existing wells. The expected drilling and completion costs per gross well are approximately $835,000 to $1.2 million and the average well depth in this area approximates 7,500 feet. Our average finding and development costs in 2002 were $0.44 per Mcfe. During 2002, capital expenditures in this area totaled $1.1 million for our participation in the drilling of 2 gross and net wells.

*Production Information.* Revenues derived from our producing properties comprised approximately 6%, 4% and 2% of consolidated revenues for the years ended December 31, 2002, 2001 and 2000, respectively. The operating margin (revenues and equity earnings from equity investments less product purchases and operating expenses) derived from our producing properties comprised approximately 33%, 24% and 14% of consolidated gross margin for the years ended December 31, 2002, 2001 and 2000, respectively. Primarily as a result of the increased investment in the Powder River Basin coal bed methane, we expect both the revenues and operating margin derived from our producing properties to continue to increase.

The following table provides a summary of our net annual production volumes:

| | Year Ending December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2002 | | 2001 | | 2000 | |
| State/Basin | Gas (MMcf) | Oil (MBbl) | Gas (MMcf) | Oil (MBbl) | Gas (MMcf) | Oil (MBbl) |
| Colorado – Sand Wash Basin | 900 | 6 | 547 | 3 | 387 | 2 |
| Texas (1) | 20 | 2 | 29 | 2 | 36 | 3 |
| Wyoming: | | | | | | |
| Powder River Basin | 42,314 | - | 31,773 | - | 25,552 | - |
| Green River Basin | 4,167 | 45 | 3,165 | 40 | 2,044 | 23 |
| Total | 47,401 | 53 | 35,514 | 45 | 28,019 | 28 |

(1) Represents a small non-operating working interest in several wells in the Austin Chalk area.

The following table provides a summary of our proved developed and proved undeveloped net reserves as of the end of the year:

| | Year Ending December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2002 | | 2001(1) | | 2000 | |
| State/Basin | Gas (MMcf) | Oil (MBbl) | Gas (MMcf) | Oil (MBbl) | Gas (MMcf) | Oil (MBbl) |
| Colorado-Sand Wash Basin | 12,624 | 53 | 11,693 | 51 | 6,658 | 30 |
| Wyoming: | | | | | | |
| Powder River Basin | 414,143 | - | 392,950 | 7 | 350,512 | - |

| | | | | | | |
|---|---|---|---|---|---|---|
| Green River Basin | 153,897 | 1,160 | 65,594 | 603 | 51,324 | 409 |
| Total | 580,664 | 1,213 | 470,237 | 661 | 408,494 | 439 |

(1) On a gas equivalent basis using December 31, 2001 pricing, total proved reserves at December 31, 2001 equates to approximately 476 Bcfe.

We employ a total staff of 14 full time reservoir and production engineers, geophysicists and geologists who complete annual reserve estimates of reserves connected to each of our existing gathering, processing and treating facilities.

The report for proved reserves in the Powder River Basin coal bed methane gas and other Wyoming assets for 2002, 2001 and 2000 has been audited by Netherland, Sewell & Associates, Inc.

Our reserve estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves, the projection of future rates of production and the timing of development expenditures. The accuracy of these estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserve estimates are imprecise and should be expected to change as additional information becomes available. Estimates of economically recoverable reserves and of future net cash flows prepared by different engineers or by the same engineers at different times may vary substantially. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of those reserves are based upon certain assumptions about production levels, prices and costs, which may not be correct. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The meaningfulness of such estimates is highly dependent upon the accuracy of the assumptions upon which they were based. Actual results may differ materially from the results estimated. Our estimates of reserves connected to our gathering and processing facilities are calculated by our reservoir engineering staff and are based on publicly available data. These estimates may be less reliable than the reserve estimates made for our own producing properties since the data available for estimates of our own producing properties also include our proprietary data.

*Midstream Operations*

Our midstream operations consist of our gathering, processing, treating, marketing and transportation operations. An important element of our long-term business plan is to meet or exceed throughput projections in these areas and to optimize their profitability. To achieve this goal, we must continue our efforts to add to natural gas throughput levels through new well connections and through the expansion or acquisition of gathering or processing systems. We also seek to increase the efficiency of our operations by modernization of equipment and the consolidation of existing facilities.

On January 31, 2003, we acquired 18 gathering systems in Wyoming, primarily located in the Green River Basin with smaller operations in the Powder River and Wind River Basins, for a total of $37.1 million. These assets were acquired from El Paso Field Services, EPFS, and related entities. These systems are comprised of a total of 550 miles of gathering lines and, at January 31, 2003, were gathering a total of 139 MMcf per day. Approximately 80% of the revenues to be derived from these facilities will be earned under long-term, fee-based contracts with the remaining revenue generated under keep-whole arrangements. The three largest systems are located near our Red Desert processing facility and will be consolidated into that facility. Four of these systems are located in the Wind River Basin and provide us with the opportunity to expand our gathering and processing activities into an area in which we have not previously operated. Six of the smaller systems are located in the Powder River Basin and will be evaluated for consolidation opportunities or divestiture.

*Gas Gathering, Processing and Treating.*

Overall, at December 31, 2002, we operated a total of 17 gathering, processing and treating facilities, or plant operations, with approximately 9,300 miles of gathering lines. These facilities are located in five states and have a combined throughput capacity of 2.9 billion cubic feet, Bcf, per day of natural gas. Our operations are located in some of the most actively drilled oil and gas producing basins in the United States. In 2002, we gathered an average of 1.2 Bcf per day of natural gas, produced natural gas for delivery to markets of 845 MMcf per day and produced 1.8 MMgal per day of NGLs. In addition to our integrated upstream and midstream operations in the Powder River and Green River Basins in Wyoming, our core assets include our plant operations located in west Texas and Oklahoma. We believe that our core assets have stable production rates, provide a significant operating cash flow and continue to provide us with strategic growth opportunities.

We contract with producers to gather raw natural gas from individual wells located near our plants or gathering systems. Once we have executed a contract, we connect wells to gathering lines through which the natural gas is delivered to a processing plant or treating facility. At a processing plant, we compress the natural gas, extract raw NGLs and treat the remaining dry gas to meet pipeline quality specifications. Five of our processing plants can further separate, or fractionate, the mixed NGL stream into ethane, propane, normal butane and natural gasoline to obtain a higher value for the NGLs, and three of our plants are capable of processing and treating natural gas containing hydrogen sulfide or other impurities that require removal prior to delivery to market pipelines.

We acquire dedicated acreage and natural gas supplies in an effort to maintain or increase throughput levels to offset natural production declines of connected wells. We obtain these natural gas supplies by connecting additional wells, purchasing existing systems from third parties and through internally developed projects or joint ventures. Historically, while individual plants have experienced declines in dedicated reserves, we have been successful in connecting additional reserves to more than offset the natural declines. Overall, the level of future drilling will depend upon, among other factors, the prices for gas and oil, the drilling budgets of third-party producers, energy and environmental policy and regulation of governmental agencies and the availability of foreign oil and gas, none of which is within our control. At December 31, 2002, our estimated reserves connected to our midstream facilities totaled 3.6 Tcf. This includes third party reserves connected to our facilities and our proven reserves. In 2002, including the reserves developed by us and associated with our partnerships and excluding the reserves and production associated with the facilities sold during this period, we connected new reserves to our facilities to replace approximately 205% of throughput.

Substantially all gas flowing through our gathering, processing and treating facilities is supplied under three types of long-term contracts providing for the purchase, treating or processing of natural gas for periods ranging from one month to twenty years or in some cases for the life of the oil and gas lease. Approximately 65% of our plant facilities' gross margins, or revenues at the plants less product purchases, for the month of December 2002 resulted from percentage-of-proceeds agreements in which we are typically responsible for the marketing of the gas and NGLs. We pay producers a specified percentage of the net proceeds received from the sale of the gas and the NGLs. This type of contract allows the producers of the natural gas and us to share proportionally in price changes.

Approximately 21% of our plant facilities' gross margins for the month of December 2002 resulted from contracts that are primarily fee-based from which we receive a set fee for each Mcf of gas gathered and/or processed. This type of contract provides us with a steady revenue stream that is not dependent on commodity prices, except to the extent that low prices may cause a producer to delay drilling. The proportion of fee-based contracts is expected to increase as the volumes from the Powder River Basin coal bed methane development increase. In addition, the majority of the revenues to be derived from the facilities acquired in January 2003 will be earned under long-term, fee-based contracts.

Approximately 14% of our plant facilities' gross margins for the month of December 2002 resulted from contracts that combine gathering, compression or processing fees with "keepwhole" arrangements or wellhead purchases. Typically, we charge producers a gathering and compression fee based upon volume. In addition, we retain a predetermined percentage of the NGLs recovered by the processing facility and keep the producers whole by returning to the producers at the tailgate of the plant an amount of residue gas equal on a Btu basis to the natural gas received at the plant inlet. The "keepwhole" component of the contracts permits us to benefit when the value of the NGLs is greater as a liquid than as a portion of the residue gas stream. However, we are adversely affected when the value of the NGLs is lower as a liquid than as a portion of the residue gas stream.

*Powder River Basin.* Our midstream operations in the Powder River Basin are fully integrated with our upstream operations. In other words, we provide the gathering, compression and processing services for both our own production and for third-party operators. As of December 31, 2002, our assets in the Powder River Basin in northeast Wyoming were primarily comprised of our coal bed methane gathering system with a capacity of 525 MMcf per day, our 13% equity interest in Fort Union Gas Gathering, L.L.C. with a gross capacity of 635 MMcf per day, and several small gas processing facilities.

Our capital budget in the Powder River Basin for midstream activities provides for expenditures of approximately $14.7 million during 2003. During 2002, our capital expenditures in this area totaled $19.9 million. We have also entered into several operating leases for compression equipment primarily in the coal bed gathering area. As of December 31, 2002, we had leased a total of 124 compression units and, during 2003 we expect to add an additional 26 compression units to these leases. Depending upon our future drilling success, we may need to make additional capital expenditures or leasing commitments to continue expansion in this basin. Due to drilling, regulatory, commodity pricing and other uncertainties, which are beyond our control, there can be no assurance that we will incur this level of capital expenditure.

In 1998, we joined with other industry participants to form Fort Union, to construct a 106-mile long, 24-inch gathering pipeline and treater to gather and treat natural gas in the Powder River Basin in northeast Wyoming. We own a 13% equity interest in Fort Union and are the construction manager and field operator. The header delivers coal bed methane gas to a treating facility near Glenrock, Wyoming and accesses interstate pipelines serving gas markets in the Rocky Mountain and Midwest regions of the United States. The gathering pipeline went into service in 1999 with a capacity of 435 MMcf per day. Construction of the gathering header and treating system was project financed by Fort Union and required a cash investment by us of approximately $900,000. In 1999, we entered into a ten-year agreement for firm gathering services on 60 MMcf per day of capacity at $0.14 per Mcf on Fort Union. In 2001, a 62-mile expansion of Fort Union was completed and brought the system's capacity to 635 MMcf per day. The expansion costs totaled approximately $22.0 million and were also project financed by Fort Union. In 2001, we invested approximately $500,000 as an equity contribution to Fort Union in conjunction with the project financing. Also in connection with the expansion, we increased our commitment for firm gathering services, effective December 2001, to a total of 83 MMcf per day of capacity at $0.14 per Mcf.

*Green River Basin.* Our midstream operations in the Green River Basin of southwest Wyoming are also fully integrated with our upstream operations in this area. Our midstream assets in this basin are comprised of the Granger and Lincoln Road facilities, or collectively the Granger complex, our 50% equity interest in Rendezvous Gas Services, L.L.C., "Rendezvous," and our Red Desert facility. These facilities have a combined gathering capacity of 465 MMcf per day and a combined processing capacity of 327 MMcf per day. During 2002 these facilities averaged throughput of 348 MMcf per day and processed 198 MMcf per day.

Our 2003 capital budget for midstream activities in this basin provides for expenditures of approximately $63.9 million during 2003. This capital budget includes approximately $21.2 million for gathering lines and installation of compression to expand the capacity of our Granger Complex, $5.6 million for additional contributions to Rendezvous for the expansion of its system and $37.1 million for the acquisition of 18 additional gathering systems in January 2003. During 2002, our capital expenditures in this area totaled $18.9 million. Due to drilling, commodity pricing and regulatory uncertainties, which are beyond our control, there can be no assurance that we will incur this level of capital expenditure.

In 2001, we sold a 50% interest in a segment of the gathering system behind our Granger facility, along with associated field compression, to an unrelated third party for $5.2 million. Together, we contributed our respective interests in this system along with additional field compression and gathering dedications for gas produced along the Pinedale Anticline to a newly formed limited liability corporation named Rendezvous. Each company owns a 50% interest in Rendezvous, and we serve as field operator of its systems. Rendezvous was formed to gather gas along the Pinedale Anticline for blending or processing at either our Granger Complex or at Questar's Blacks Fork processing facility. Rendezvous was expanded during 2001 and 2002 to increase its capacity to 275 MMcf per day. At December 31, 2002, Rendezvous was gathering 190 MMcf per day and we had a total of $22.8 million invested in this venture. A further expansion is proposed for 2003, subject to the necessary approvals, which would extend the system approximately 30 miles further into the Pinedale Anticline at an estimated cost of $10.5 million gros, of which our share is approximately $5.2 million.

*West Texas.* Our primary assets in west Texas are the Midkiff/Benedum complex and the Gomez treating facility. These facilities process gas produced by third parties in the Permian Basin, have a combined operational capacity of 565 MMcf per day and processed an average of 291 MMcf per day in 2002. In 2002, these facilities produced an average of 214 MMcf per day of natural gas for delivery to sales markets and produced an average of 859 MGal per day of NGLs. Our capital budget in this area provides for expenditures of approximately $6.0 million during 2003. This capital budget includes approximately $2.7 million for additions to the gathering systems and plant facilities and approximately $3.3 million for replacing and upgrading field and plant equipment. During 2002, we expended $8.4 million in this area.

In order to remain competitive with other plant operators in the gathering, processing and treating business, it is important to be a low-cost, efficient operator. Over the past several years, we have invested $29.0 million to replace older compressors at our Midkiff/Benedum complex with fuel-efficient equipment. This upgrade has resulted in lower maintenance costs, reduced emissions and a decrease in our fuel consumption, thereby increasing the natural gas available for sale and our ability to attract additional volumes to our system.

*Oklahoma.* Our primary assets in Oklahoma are the Chaney Dell and Westana systems. These facilities process gas produced by third parties in the Anadarko Basin and have a combined operational capacity of 175 MMcf per day. In 2002, these facilities processed an average of 147 MMcf per day, produced an average of 128 MMcf per day of natural gas for delivery to sales markets and produced 330 MGal per day of NGLs. Our capital budget in this area provides for expenditures of approximately $9.0 million during 2003. This capital budget includes approximately $5.5 million for additions to the gathering systems and plant facilities and approximately $3.5 million for replacing and upgrading field and plant equipment. During 2002, we expended $9.4 million in this area.

***San Juan.*** Our assets in the San Juan Basin of New Mexico are the San Juan River processing facility and the Four Corners Gathering system. These facilities gather and process gas produced by third parties in the San Juan and Paradox Basins and have a combined operational capacity of 75 MMcf per day. In 2002, these facilities gathered and processed an average of 27 MMcf per day, produced an average of 23 MMcf per day of natural gas for delivery to sales markets and produced 45 MGal per day of NGLs. Our capital budget in this area provides for expenditures of approximately $1.5 million during 2003. During 2002, we expended $2.4 million in this area.

*Principal Facilities.* The following tables provide information concerning our principal facilities during 2002. We also own and operate several smaller treating, processing and transportation facilities located in the same areas as our other facilities.

| Facilities (1) | Year Placed In Service | Gas Gathering System Miles (2) | Gas Throughput Capacity (MMcf/D) (3) | Average for the Year Ended December 31, 2002 Gas Throughput (MMcf/D) (4) | Gas Production (MMcf/D) (5) | NGL Production (MGal/D) (5) |
|---|---|---|---|---|---|---|
| Texas | | | | | | |
| Gomez Treating (6) | 1971 | 386 | 280 | 92 | 83 | - |
| Midkiff/Benedum | 1949 | 2,222 | 165 | 140 | 93 | 858 |
| Mitchell Puckett Gathering (6) | 1972 | 93 | 120 | 59 | 38 | 1 |
| Louisiana | | | | | | |
| Toca (7)(8)(14) | 1958 | - | 160 | 50 | 48 | 40 |
| Wyoming | | | | | | |
| Coal Bed Methane Gathering | 1990 | 1,298 | 525 | 379 | 203 | - |
| Fort Union Gas Gathering | 1999 | 106 | 635 | 453 | 453 | - |
| Granger (7)(9)(10) | 1987 | 532 | 235 | 200 | 149 | 299 |
| Hilight Complex (7) | 1969 | 626 | 124 | 15 | 10 | 52 |
| Kitty/Amos Draw (7) | 1969 | 314 | 17 | 7 | 5 | 31 |
| Lincoln Road (10) | 1988 | 149 | 50 | 13 | 12 | 4 |
| Newcastle (7) | 1981 | 146 | 5 | 3 | 2 | 20 |
| Red Desert (7) | 1979 | 111 | 42 | 13 | 11 | 22 |
| Rendezvous Gas Services | 2001 | - | 275 | 122 | 122 | - |
| Reno Junction (9) | 1991 | - | - | - | - | 105 |
| Oklahoma | | | | | | |
| Chaney Dell | 1966 | 2,093 | 130 | 66 | 52 | 325 |
| Westana | 1981 | 1,017 | 45 | 81 | 76 | 5 |
| New Mexico | | | | | | |
| San Juan River (6) | 1955 | 140 | 60 | 25 | 21 | 34 |
| Utah | | | | | | |
| Four Corners Gathering | 1988 | 104 | 15 | 2 | 2 | 11 |
| Total | | 9,337 | 2,883 | 1,720 | 1,380 | 1,807 |

| Transportation Facilities (1) | Year Placed In Service | Transportation Miles(2) | Average for the Year Ended December 31, 2002 Pipeline Capacity (MMcf/D)(2) | Gas Throughput (MMcf/D)(4) |
|---|---|---|---|---|
| MIGC (11)(13) | 1970 | 245 | 130 | 180 |
| MGTC (12) | 1963 | 252 | 18 | 12 |
| Total | | 497 | 148 | 192 |

Footnotes on following page.

(1) Our interest in all facilities is 100% except for Midkiff/Benedum (73%); Newcastle (50%); Fort Union gathering system (13%); and Rendezvous Gas Services (50%). We operate all facilities, and all data include our interests and the interests of other joint interest owners and producers of gas volumes dedicated to the facility. Unless otherwise indicated, all facilities shown in the table are gathering, processing or treating facilities.
(2) Gas gathering system miles, transportation miles and pipeline capacity are as of December 31, 2002.
(3) Gas throughput capacity is as of December 31, 2002 and represents capacity in accordance with design specifications unless other constraints exist, including permitting or field compression limits.
(4) Aggregate wellhead natural gas volumes collected by a gathering system or volumes transported by a pipeline.
(5) Volumes of gas and NGLs are allocated to a facility when a well is connected to that facility; volumes exclude NGLs fractionated for third parties.
(6) Sour gas facility (capable of processing or treating gas containing hydrogen sulfide and/or carbon dioxide).
(7) Processing facility that includes fractionation (capable of fractionating raw NGLs into end-use products).
(8) Straddle plant, or a plant located near a transportation pipeline that processes gas dedicated to or gathered by a pipeline company or another third-party.
(9) NGL production includes conversion of third-party feedstock to iso-butane.
(10) Lincoln Road is operated on an intermittent basis to process excess gas from the Granger system.
(11) MIGC is an interstate pipeline located in Wyoming and is regulated by the Federal Energy Regulatory Commission.
(12) MGTC is a public utility located in Wyoming and is regulated by the Wyoming Public Service Commission.
(13) Pipeline capacity represents certificated capacity at the Powder River junction only and does not include interruptible capacity or capacity at other delivery points.
(14) This facility was sold in September 2002.

We routinely review the economic performance of each of our operating facilities to ensure that a satisfactory rate of return is achieved. If an operating facility is not generating targeted returns we will explore various options, such as consolidation with other Western-owned or third-party-owned facilities, dismantlement, asset trades or sale. A description of the significant midstream acquisitions and dispositions since January 1, 1998, involving assets other than those located in the Powder River Basin, Green River Basin, West Texas or Oklahoma which were previously discussed, are:

*Toca Processing Facility.* In June 2002, we entered into an agreement for the sale of our Toca processing facility in Louisiana. This sale closed in September 2002. The sale price was $32.2 million, subject to accounting adjustments, and resulted in a pre-tax loss of approximately $448,000. The purchase price included a natural gas processing plant with a capacity of 160 million cubic feet per day and a fractionator that can separate 14,200 barrels per day of mixed natural gas liquids into propane, normal butane, iso-butane and natural gasoline. The sale also included NGL storage as well as truck, rail and barge loading facilities, which support the complex.

*Bethel Treating Facility.* In 1996 and 1997, the Pinnacle Reef exploration area was rapidly developing into a very active lease acquisition and exploratory drilling area using 3-D seismic technology to identify prospects. The initial discoveries indicated a large potential gas development. Based on our receipt of large acreage dedications in this area, we, through our wholly-owned subsidiary Pinnacle Gas Treating, Inc., constructed the Bethel treating facility for a total cost of approximately $102.8 million. This facility was comprised of a 300 MMcf per day treating facility and 86 miles of associated gathering assets located in east Texas.

In 1998, because of uncertainties related to the pace and success of third-party drilling programs, declines in volumes produced at several wells and other conditions outside our control, we determined that an evaluation of the Bethel treating facility, in accordance with accounting standards, was necessary. We compared the net book value of the assets to the discounted expected future cash flows of the facility and determined that the results of this comparison required a pre-tax, non-cash impairment charge of $77.8 million.

In 2000, we signed an agreement for the sale of all the outstanding stock of this subsidiary for $38.0 million. The sale closed in January 2001 and resulted in a net pre-tax gain for financial reporting purposes of $12.1 million in the first quarter of 2001.

*Arkoma.* In August 2000, we sold our Arkoma Gathering System in Oklahoma for gross proceeds of $10.5 million. This sale resulted in a pre-tax gain of $3.9 million.

*Westana.* In February 2000, we acquired the remaining 50% interest in the Westana Gathering Company for a net purchase price of $9.8 million.

*Western Gas Resources-California, Inc.* In January 2000, we sold all of the outstanding stock of our wholly owned subsidiary, Western Gas Resources-California, Inc., or WGR-California, for $14.9 million. The only asset of this subsidiary was a 162-mile pipeline in the Sacramento Basin of California. WGR-California acquired the pipeline through the exercise of a purchase option in a transaction that closed immediately prior to the sale by us of WGR-California. We recognized a pre-tax gain on the sale of approximately $5.4 million in 2000.

*Black Lake.* In December 1999, we signed an agreement for the sale of our Black Lake facility and related reserves for gross proceeds of $7.8 million. This sale closed in January 2000. This transaction resulted in an approximate pre-tax loss of $7.3 million, which was recognized in 1999.

*MiVida.* In June 1999, we sold our MiVida treating facility for gross proceeds of $12.0 million. This transaction resulted in an approximate pre-tax gain of $1.2 million.

*Katy.* In April 1999 we sold all the outstanding common stock of our wholly owned subsidiary, Western Gas Resources Storage, Inc., for gross proceeds of $100.0 million. This transaction resulted in an approximate pre-tax loss of $17.7 million in 1999. The only asset of this subsidiary was the Katy facility. We also sold 5.1 Bcf of stored gas in the Katy facility for total sales proceeds of $11.7 million, which approximated our cost of the inventory.

*Giddings.* In April 1999, we sold our Giddings facility for gross proceeds of $36.0 million, which resulted in an approximate pre-tax loss of $6.6 million in 1999.

*Edgewood.* In two transactions, which closed in October 1998, we sold our Edgewood gathering system, including our undivided interest in the producing properties associated with this facility, and our 50% interest in the Redman Smackover Joint Venture. The combined sales price was $55.8 million. We recognized a pre-tax gain of approximately $1.6 million during 1998.

*Transportation.*

We own and operate MIGC, Inc. an interstate pipeline located in the Powder River Basin in Wyoming, and MGTC, Inc. an intrastate pipeline located in northeast Wyoming. MIGC charges a Federal Energy Regulatory Commission, FERC, approved tariff and is connected to pipelines owned by Colorado Interstate Gas Company, Williston Basin Interstate Pipeline Company, Kinder Morgan Interstate Pipeline Co., Wyoming Interstate Company, Ltd. and MGTC. During 2002, MIGC transported an average of 180 MMcf per day. It is anticipated that MIGC will continue to operate around that level through 2003. MIGC earns fees on a monthly basis from firm capacity contracts under which the shipper pays for transport capacity whether or not the capacity is used and from interruptible contracts where a fee is charged based upon volumes received into the pipeline. Contracts for firm capacity on MIGC range in duration from one month to six years and the fees charged average $0.33 per Mcf.

The FERC has implemented changes over the past several years to restrict transactions between regulated pipelines and affiliated companies. In addition, the FERC has proposed to limit the use of affiliates' employees in the operation of regulated entities. In August 2002, the FERC issued a Notice of Proposed Rule Making that, if enacted, would require MIGC to establish its own cash management function, including its own revolving credit facility, and would limit the ability of MIGC to transfer funds to us. Further, this proposed rule may require us to modify our existing subsidiary guarantees under our debt agreements. We can make no assurances as to the ultimate regulations passed by the FERC or the effects such regulations may have on the operating costs of MIGC or our financial position.

MGTC provides transportation and gas sales to the Wyoming cities of Gillette, Moorcroft and Wright at rates that are subject to the approval of the Wyoming Public Service Commission. During 2002, MGTC transported an average of 12 MMcf per day and sold an average of 1 MMcf per day.

*Marketing.*

*Gas.* We market gas produced at our wells and our plants and purchased from third parties to end-users, local distribution companies, or LDCs, pipelines and other marketing companies throughout the United States and Canada. In addition to our offices in Denver, we have marketing offices in Houston, Texas and Calgary, Alberta. Historically, our gas marketing was an outgrowth of our gas processing activities and was directed toward selling gas processed at our plants to ensure their efficient operation. As the natural gas industry became deregulated and offered more opportunity, we increased our third-party gas marketing. Third-party sales, firm transportation capacity on interstate pipelines and our gas storage positions, combined with the stable supply of gas from our facilities and production, enable us to respond quickly to changing market conditions and to take advantage of seasonal price variations and peak demand periods. For the year ended December 31, 2002, our total gas sales volumes averaged 2.0 Bcf per day, of which 447 MMcf per day was produced at our plants or from our producing properties.

One of the primary goals of our gas marketing operations continues to be the preservation and enhancement of the value received for our equity volumes of natural gas. This goal is achieved through the use of hedges on the production of our equity natural gas and through the use of firm transportation capacity. For example, during 2002, as a result of limited pipeline capacity from the Rocky Mountain region to market centers in the mid-continent and west coast areas, natural gas in this region has sold at a substantial discount to these other market areas. We had commodity price hedges and firm transportation capacity to the mid-continent markets on approximately 92% of our equity production in the Rocky Mountain area for 2002. This allowed us to realize an approximate $0.90 per Mcf improvement in price for natural gas per MMbtu relative to what would have been received if these hedges and capacity rights had not existed. We have similar hedges and transportation positions for approximately 99% of estimated 2003 equity production of natural gas in the Rocky Mountain region.

We sell gas under agreements with varying terms and conditions in order to match seasonal and other changes in demand. The average duration as of December 31, 2002 of our sales contracts was 15 months. The marketing of products purchased from third parties typically results in low operating margins relative to the sales price. Revenues for sales of product are recognized at the time the gas is delivered to the customer and are sensitive to changes in the market prices of the underlying commodities. We record revenue on our physical gas marketing activities on a gross basis versus sales net of purchases basis. We believe that this presentation is required because we obtain title to all the gas that we buy including third-party purchases, bear the risk of loss and credit exposure on these transactions and it is our intention upon entering these contracts to take physical delivery of the natural gas. Gains and losses on any accompanying financial transactions are recorded net. Additionally, for our marketing activities, we utilize mark-to-market accounting. Under mark-to-market accounting, the expected margin to be realized over the term of the transaction is recorded in the month of origination. To the extent that a transaction is not fully hedged or there is any hedge ineffectiveness, additional gains or losses associated with the transaction may be reported in future periods. During the year ended December 31, 2002, we sold gas to approximately 255 end-users, pipelines, LDCs and other customers. Two customers accounted for approximately 10% of our consolidated revenues from the sale of gas, or 9% of total consolidated revenue, for the year ended December 31, 2002. One of these customers is an energy merchant and the other customer is an electric utility. We are not currently entering into new transactions with the energy merchant. In general, we do not expect to increase our third-party sales volumes in 2003 significantly from levels achieved over the last several years, and in fact, due to price volatility and credit concerns in the energy industry, our overall sales volumes may decrease.

*NGLs.* We market NGLs, or ethane, propane, iso-butane, normal butane, natural gasoline and condensate, produced at our plants and purchased from third parties, in the Rocky Mountain, Mid-Continent and Southwestern regions of the United States. A majority of our production of NGLs moves to the Gulf Coast area, which is the largest NGL market in the United States. Through the development of end-use markets and distribution capabilities, we seek to ensure that products from our plants move on a reliable basis, avoiding curtailment of production. For the year ended December 31, 2002, NGL sales averaged 2,010 MGal per day, of which 1,417 MGal per day was produced at our plants.

Consumers of NGLs are primarily the petrochemical industry, the petroleum refining industry and the retail and industrial fuel markets. As an example, the petrochemical industry uses ethane, propane, normal butane and natural gasoline as feedstocks in the production of ethylene, which is used in the production of various plastics products. Over the last several years, the petrochemical industry has increased its use of NGLs as a major feedstock and is projected to continue to increase such usage. Further, consumers use propane for home heating, transportation and agricultural applications. Price, seasonality and the economy primarily affect the demand for NGLs.

We decreased NGL sales to third parties by approximately 340 MGal per day in the year ended December 31, 2002 compared to 2001. With the sale of our Toca facility in September 2002, we anticipate that sales of third-party product will decrease further. As in the case of natural gas, we continually monitor and review the credit exposure to our NGL marketing counter parties.

During the year ended December 31, 2002, we sold NGLs to 102 customers including end-users, fractionators, chemical companies and others. Three customers accounted for approximately 38% of our consolidated revenues from the sale of NGLs, or 5% of total consolidated revenue, for the year ended December 31, 2002. One of these customers is a large integrated energy company, another is a large petrochemical company and the third is an energy merchant. We are not currently entering into new transactions with the energy merchant. We also derive revenues from contractual marketing fees charged to some producers for NGL marketing services. For the year ended December 31, 2002, these fees were less than 1% of our consolidated revenues.

We sell NGLs under agreements with varying terms and conditions in order to match seasonal and other changes in demand. At December 31, 2002, the terms of our sales contracts range from one month to five years. The marketing of products purchased from third parties typically results in low operating margins relative to the sales price. Revenues for sales of NGLs are recognized at the time the NGLs are delivered to the customer and are sensitive to changes in the market prices of the underlying commodities. We record revenue on our physical NGL marketing activities on a gross sales versus sales net of purchases basis. We believe that this presentation is required because we obtain title to all the NGLs that we buy including third-party purchases, bear the risk of loss and credit exposure on these transactions and it is our intention upon entering these contracts to take physical delivery of the product. Gains and losses on any accompanying financial transactions are recorded net. Additionally, for our marketing activities we utilize mark-to-market accounting. Under mark-to-market accounting, the expected margin to be realized over the term of the transaction is recorded in the month of origination. To the extent that a transaction is not fully hedged or there is any hedge ineffectiveness, additional gains or losses associated with the transaction may be reported in future periods.

*Environmental*

The construction and operation of our gathering systems, plants and other facilities used for the gathering, processing, treating or transporting of gas and NGLs are subject to federal, state and local environmental laws and regulations, including those that can impose obligations to clean up hazardous substances at our facilities or at facilities to which we send wastes for disposal. In most instances, the applicable regulatory requirements relate to water and air pollution control or waste management. We employ an environmental manager, a safety manager, four environmental engineers, three safety specialists and three regulatory compliance specialists to monitor environmental and safety compliance at our facilities. In addition, on an ongoing basis, the environmental engineers perform environmental assessments of our existing facilities. We believe that we are in substantial compliance with applicable material environmental laws and regulations. Environmental regulation can increase the cost of planning, designing, constructing and operating our facilities. The costs for compliance with current environmental laws and regulations have not had and, we believe, will not have a material adverse effect on our financial position or results of operations.

Prior to consummating any major acquisition, our environmental engineers perform audits on the facilities to be acquired. In conducting this audit on the gathering systems acquired from EPFS, in January 2003, we identified many well sites that include underground sump tanks, pits, or tinhorns that are not properly permitted according to Wyoming Oil and Gas Conservation Commission, or WYOGCC, regulations. We have reported these violations to WYOGCC and are providing it with our remediation plan. It is our intention to remove all these underground facilities over the next several months. Based on our discussions with WYOGCC, it is our belief that it will not pursue any type of fines or penalties from us related to these assets. We believe the cost of our remediation plan will approximate $1.5 million, and EPFS has established an escrow account in that amount to reimburse us for these and other costs. In addition, at the time of the acquisition, we obtained an insurance policy that we believe will cover any additional environmental issues that may be identified over the next three years associated with these assets, up to a total exposure of $5.0 million.

The Texas Council on Environmental Quality, which has authority to regulate, among other things, stationary air emissions sources, has created a committee to make recommendations to it regarding a voluntary emissions reduction plan for the permitting of existing "grand-fathered" air emissions sources within Texas. A "grand-fathered" air emissions source is one that does not need a state operating permit because it was constructed prior to 1971. We operate a number of these sources within Texas, including portions of our Midkiff/Benedum, Gomez and Mitchell Puckett systems. In connection with a modernization program, which was completed in March 2002, we replaced the majority of our "grand-fathered" equipment in Texas. We believe that the potential cost of complying with these regulations for our remaining "grand-fathered" equipment will not have material effect on our results of operations or financial position.

We anticipate that the trend in environmental legislation and regulation will continue to be toward stricter standards. Federal regulations regarding spill prevention and containment have recently been modified to establish a lower threshold of storage capacity of petroleum and petroleum by-products at a site for which a spill prevention plan is required. We are evaluating all our assets for compliance with this regulation and estimate that approximately 100 existing sites will need to be modified to meet the new requirements. We currently estimate our costs for compliance to be approximately $2.0 million. The new spill prevention plans must be in place for covered assets by April 2003. All modifications called for in those plans must be in place by August 2003. We are unaware of any other future environmental standards that are reasonably likely to be adopted that will have a material effect on our financial position or results of operations, but we cannot rule out that possibility.

We are in the process of voluntarily cleaning up substances at certain facilities that we operate. Our expenditures for environmental evaluation and remediation at existing facilities have not been significant in relation to our results of operations and totaled approximately $1.4 million for the year ended December 31, 2002, including approximately $587,000 in air emissions fees to the states in which we operate. Although we anticipate that such environmental expenses per facility will increase over time, we do not believe that such increases will have a material effect on our financial position or results of operations.

*Competition*

We compete with other companies in the gathering, processing, treating and marketing businesses both for supplies of natural gas and for customers for our natural gas and NGLs, and for the acquisition of leaseholds and other assets. Competition for natural gas supplies is primarily based on the efficiency and reliability of our services, the availability of transportation and the ability to obtain a satisfactory price for natural gas and NGLs. Our competitors for obtaining additional gas supplies, for gathering and processing gas and for marketing gas and NGLs include national and local gas gatherers and processors, brokers, marketers and distributors of various sizes and experience. The majority of these competitors have greater financial resources than do we. For customers that have the capability of using alternative fuels, such as oil and coal, we also compete for their business based on the price and availability of such alternative fuels. Our competitors for obtaining leaseholds include major and large independent oil companies as well as smaller independent oil companies and brokers. Competition for oil field services, including drilling rigs, could affect future drilling plans and costs. Competition for sales customers is primarily based upon reliability and price of deliverable natural gas and NGLs. Suppliers in our gas marketing transactions may request additional financial security such as letters of credit that are not required of some of our competitors.

*Regulation*

Our purchase and sale of natural gas and NGLs and the fees we receive for gathering and processing have generally not been subject to regulation. However, some aspects of our business are subject to federal, state and local laws and regulations that have a significant impact upon our overall operations.

As a producer, processor and marketer of natural gas, we depend on the transportation and storage services offered by various interstate and intrastate pipeline companies for the delivery and sale of our own gas supplies as well as those we process and/or market for others. Both the interstate pipelines' performance of transportation and storage services, and the rates charged for such services, are subject to the jurisdiction of the FERC, under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. At times, other system users can pre-empt the availability of interstate transportation and storage services necessary to enable us to make deliveries and/or sales of gas in accordance with FERC-approved methods for allocating the system capacity of open access pipelines. Moreover, the rates the pipelines charge for such services are often subject to negotiation between shippers and the pipelines within certain FERC-established parameters and will periodically vary depending upon individual system usage and other factors. An inability to obtain transportation and/or storage services at competitive rates can hinder our processing and marketing operations and/or adversely affect our sales margins.

Generally, neither the FERC nor any state agency regulates gathering and processing prices. The Oklahoma Corporation Commission, or the OCC, has limited authority in certain circumstances, after the filing of a complaint by a producer, to compel a gas gatherer to provide open access gathering and to set aside unduly discriminatory gathering fees. The Oklahoma state legislature is considering legislation that would expand the authority of the OCC to compel a gas gatherer to publish rates, terms and conditions of its service and under some circumstances, to justify those charges. We do not believe that any of the proposed legislation of which we are aware is likely to have a material adverse effect on our financial position or results of operations. However, we cannot predict what additional legislation or regulations the states may adopt regarding gas gathering.

The construction of additional gathering, processing and treating facilities and the development of natural gas reserves require permits from several federal, state and local agencies. In the past we have been successful in receiving all permits necessary to conduct our operations. There can be no assurance, however, that permits in the future will be obtainable or issued timely or that the terms of any permits will be compatible with our business plans.

*Employees*

At December 31, 2002, we employed 636 full-time employees, of which 371were employed at field locations. None of our employees is a union member. We consider relations with employees to be excellent.

## ITEM 3. LEGAL PROCEEDINGS

Reference is made to Note 8 of our Consolidated Financial Statements in Item 8 of this Form 10-K.

## ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders during the quarter ended December 31, 2002.

## PART II

### ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

As of March 3, 2003, there were 33,099,577 shares of common stock outstanding held by 198 holders of record. The common stock is traded on the New York Stock Exchange, or NYSE, under the symbol "WGR". The following table sets forth quarterly high and low sales prices as reported by the NYSE Composite Tape for the quarterly periods indicated.

| | HIGH | LOW |
|---|---|---|
| **2002** | | |
| Fourth Quarter | $ 38.00 | $ 30.35 |
| Third Quarter | 37.54 | 25.00 |
| Second Quarter | 40.12 | 35.24 |
| First Quarter | 37.50 | 28.22 |
| **2001** | | |
| Fourth Quarter | $ 35.65 | $ 26.08 |
| Third Quarter | 33.59 | 24.88 |
| Second Quarter | 43.50 | 31.64 |
| First Quarter | 33.70 | 25.33 |

We paid annual dividends on our common stock aggregating $0.20 per share during the years ended December 31, 2002 and 2001. We have declared a dividend of $0.05 per share of common stock for the quarter ending March 31, 2003 to holders of record as of March 28, 2003. Declarations of dividends on our common stock are within the discretion of the board of directors. In addition, our ability to pay dividends on our common stock is restricted by covenants in our financing facilities, the most restrictive of which is in our subordinated note indenture and that covenant prohibits declaring or paying dividends that exceed, in the aggregate, the sum of $20 million plus 50% of our consolidated net operating income (as defined in the indenture) earned after July 1, 1999 (or minus 100% if a net loss) plus the aggregate net cash proceeds received after July 1, 1999 from the sale of any stock. At December 31, 2002, availability under this covenant was approximately $42.8 million.

*Equity Compensation Plan Information*

The following table summarizes our equity compensation plans under which securities may be issued as of December 31, 2002. The only types of equity compensation plans that we have are plans that authorize the granting of options to purchase shares of our common stock.

| Plan Category | Number of securities to be issued upon exercise of outstanding options (a) | Weighted-average exercise price of outstanding options (b) | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a) (c) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 1,051,812 | $ 28.67 | 1,154,003 |
| Equity compensation plans not approved by security holders | 308,350 | $ 24.48 | - |
| Total | 1,360,162 | $ 27.72 | 1,154,003 |

A description of the equity compensation plans that were not approved by the security holders is as follows.

***1999 Non-Employee Directors Stock Option Plan.*** Effective March 1999, our board of directors adopted a stock option plan that authorized the granting of options to purchase 15,000 shares of our common stock to non-employee directors. During

1999, the board approved grants of options covering a total of 15,000 shares of our common stock to several board members. The exercise price of the stock underlying each option was the average closing price for the ten days prior to the grant. Under this plan, options covering up to 33 1/3% of the underlying shares are exercisable on each anniversary from the date of grant and the director must exercise the option within five years of the date each option vests. This plan terminates on the earlier of March 12, 2009 or the date on which all options granted under the plan have been exercised in full.

***Chief Executive Officer and President's Plan.*** Pursuant to his employment agreement, dated October 15, 2001, and the stock option agreement, dated as of November 1, 2001, between us and Peter A. Dea, our CEO and President, we granted non-qualified stock options to Mr. Dea for the purchase of 300,000 shares our common stock. The exercise price of the options was equal to $5.00 below the closing price per share on the effective date of his employment agreement. The stock options are subject to the conditions of the agreements and vest equally over four years and must be exercised within five years of the date on which they vest. The difference between the closing price on the effective date and the exercise price is being amortized over four years as compensation expense.

## ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth selected consolidated historical financial and operating data for Western. Certain prior year amounts have been reclassified to conform to the presentation used in 2002. The data for the three years ended December 31, 2002, 2001 and 2000 should be read in conjunction with our Consolidated Financial Statements and the notes thereto included elsewhere in this Form 10-K. The selected consolidated financial data for the years ended December 31, 1999 and 1998 are derived from our audited historical Consolidated Financial Statements. See also Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations."

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 1999 | 1998 |
| | (000s, except per share amounts and operating data) | | | | |
| **Statement of Operations:** | | | | | |
| Revenues | $ 2,489,698 | $ 3,353,162 | $ 3,280,091 | $ 1,909,288 | $ 2,115,995 |
| Gross profit (a) | 144,430 | 200,780 | 149,155 | 67,289 | 50,090 |
| Income (loss) before income taxes | 80,703 | 152,126 | 91,384 | (25,184)(b) | (105,623)(b) |
| Provision (benefit) for income taxes | 30,114 | 56,489 | 33,562 | (9,167) | (38,418) |
| Income (loss) before extraordinary items | 50,589 | 95,637 | 57,822 | (16,017)(b) | (67,205)(b) |
| Extraordinary charge for early extinguishment of debt | - | - | (1,714) (c) | (1,107)(c) | - |
| Net income (loss) | 50,589 | 95,637 | 56,108 | (17,124)(b) | (67,205)(b) |
| Earnings (loss) per share of common stock | 1.26 | 2.59 | 1.42 | (.86) | (2.42) |
| Earnings (loss) per share of common stock - assuming dilution | 1.23 | 2.48 | 1.39 | (.86) | (2.42) |
| **Other financial data:** | | | | | |
| Net cash provided by operating activities | 131,136 | 153,267 | 116,262 | 95,184 | (35,570) |
| Net cash provided by (used in) investing activities | (105,772) | (131,657) | (82,039) | 67,284 | (26,441) |
| Net cash provided by (used in) financing activities | (28,084) | (24,506) | (35,358) | (152,806) | 46,634 |
| Capital expenditures | 125,600 | 163,977 | 108,536 | 80,089 | 105,216 |
| **Balance Sheet Data** (at year end): | | | | | |
| Total assets | 1,302,144 | 1,267,942 | 1,431,422 | 1,049,486 | 1,219,377 |
| Long-term debt | 359,933 | 366,667 | 358,700 | 378,250 | 504,881 |
| Stockholders' equity | 483,068 | 473,352 | 391,534 | 349,743 | 385,216 |
| Dividends on preferred stock | 9,198 | 11,167 | 10,416 | 10,439 | 10,439 |
| Dividends on common stock | 6,603 | 6,524 | 6,448 | 6,426 | 6,430 |
| Dividends per share of common stock | .20 | .20 | .20 | .20 | .20 |
| **Operating Data:** | | | | | |
| Average gas sales (MMcf/D) | 1,988 | 1,961 | 1,835 | 1,900 | 2,200 |
| Average NGL sales (MGal/D) | 2,010 | 2,347 | 3,085 | 2,885 | 4,730 |
| Average gas volumes gathered (MMcf/D) | 1,163 | 1,161 | 1,248 | 1,168 | 1,162 |
| Facility capacity (MMcf/D) | 2,581 | 2,574 | 2,374 | 2,485 | 2,237 |
| Average gas prices ($/Mcf) | $ 2.92 | $ 3.97 | $ 3.90 | $ 2.17 | $ 2.01 |
| Average NGL prices ($/Gal) | $ .42 | $ .49 | $ .52 | $ .33 | $ .26 |

(a) Excludes selling and administrative, interest, restructuring and income tax expenses, expenses for the impairment of property and equipment, (gains) or losses on sales of assets, and any extraordinary items. See further discussion in notes (b), (c) and (d).

(b) Statement of Financial Accounting Standards No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," or SFAS No. 121, required that an impairment loss be recognized when the carrying amount of an asset exceeds its fair market value or the expected future undiscounted net cash flows. In accordance with SFAS No. 121, we recognized a pre-tax, non-cash loss on the impairment of property and equipment of $1.2 million, or $0.7 million after-tax, and $108.5 million, or $69.0 million after-tax, for the years ended December 31, 1999 and 1998, respectively.

(c) We recognized an after-tax extraordinary charge on the early extinguishment of long-term debt in 2000 and in 1999 of $1.7 million and $1.1 million, respectively.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis relates to factors that have affected our consolidated financial condition and results of operations for the three years ended December 31, 2002, 2001 and 2000. Certain prior year amounts have been reclassified to conform to the presentation used in 2002. Reference should also be made to our Consolidated Financial Statements and related Notes thereto and the Selected Financial Data included elsewhere in this Form 10-K.

*Results of Operations*

**Year ended December 31, 2002 compared to year ended December 31, 2001**
**(000s, except per share amounts and operating data)**

| | Year Ended December 31, 2002 | Year Ended December 31, 2001 | Percent Change |
|---|---|---|---|
| **Financial results:** | | | |
| Revenues | $ 2,489,698 | $ 3,353,162 | (26) |
| Gross profit | 144,430 | 200,780 | (28) |
| Net income (loss) | 50,589 | 95,637 | (47) |
| Income (loss) per share of common stock | 1.26 | 2.59 | (51) |
| Income (loss) per share of common stock - assuming dilution | 1.23 | 2.48 | (50) |
| Net cash provided by operating activities | $ 131,136 | $ 153,267 | (14) |
| **Operating data:** | | | |
| Average gas sales (MMcf/D) | 1,988 | 1,961 | 1 |
| Average NGL sales (MGal/D) | 2,010 | 2,347 | (14) |
| Average gas prices ($/Mcf) | $ 2.92 | $ 3.97 | (26) |
| Average NGL prices ($/Gal) | $ .42 | $ .49 | (14) |

Net income decreased $45.0 million for the year ended December 31, 2002 compared to 2001. The decrease in net income is primarily attributable to significantly lower gas and NGL prices in this period as compared to the prior year and lower margins per unit earned on our sales of natural gas. These decreases more than offset increased production from the Powder River Basin coal bed methane development.

Revenues from the sale of gas decreased $725.6 million to $2.1 billion for the year ended December 31, 2002 compared to 2001. This decrease was primarily due to a decline in product prices, which more than offset an increase in sales volume in the year ended December 31, 2002. Average gas prices realized by us decreased $1.05 per Mcf to $2.92 per Mcf in the year ended December 31, 2002 compared to 2001. Included in the realized gas price were approximately $28.7 million of gains recognized in the year ended December 31, 2002 related to futures positions on equity gas volumes. We have entered into additional futures positions for the majority of our equity gas for 2003. See further discussion in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk". Average gas sales volumes increased minimally to 1,988 MMcf per day in the year ended December 31, 2002 compared to 2001.

On June 5, 2002, and as amended on June 18, 2002, we responded to a data request of the FERC in Docket No. PA02-2-000. The FERC's request inquired as to any "wash", "round trip", or "sell, buy back" trading in the United States portion of the Western States Coordinating Council and/or Texas during the years ended December 31, 2000 and 2001. During this time period, we engaged in two transactions that met the FERC's criteria for a transaction of this type. The transactions occurred in April 2001 and involved an aggregate quantity of approximately 259,000 MMbtu or $3.5 million of gross revenue. The transactions were not entered into for the purpose of artificially inflating our sales volume or revenue. Our internal control policies require valuation of the current market value of gas placed in storage based upon objective criteria, and these transactions were intended to provide a third-party generated price for natural gas placed in storage. These transactions represented 0.1% of our total sales revenues for the year ended December 31, 2001. The FERC has not inquired as to sales activity in 2002. However, during 2002, no transactions of this type are included in our revenues.

Revenues from the sale of NGLs decreased approximately $114.4 million to $309.7 million in the year ended December 31, 2002 compared to 2001. This decrease is due to a reduction in product prices and to a reduction in sales volume. Average NGL prices realized by us decreased $0.07 per gallon to $0.42 per gallon in the year ended December 31, 2002 compared to 2001. Included in the realized NGL price were approximately $8.5 million of losses recognized in the year ended December 31, 2002 related to futures positions on equity NGL volumes. We have entered into additional futures positions for a portion of our equity NGL production for 2003. See further discussion in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk". Average NGL sales volumes decreased 337 MGal per day to 2,010 MGal per day in the year ended December 31, 2002 compared to 2001.

Product purchases decreased by $829.8 million for the year ended December 31, 2002 compared to 2001 primarily as a result of the decrease in commodity prices. Overall, combined product purchases as a percentage of sales of all products decreased to 89% for the year ended December 31, 2002 from 92% for 2001. The decrease in the product purchase percentage for the year ended December 31, 2002 versus 2001 resulted from a decrease in product prices and an increase of sale of our production from the Powder River Basin development.

Marketing margins on residue gas averaged $0.04 and $0.06 per Mcf in the years ended December 31, 2002 and 2001, respectively. The decrease in margin for 2002 compared to 2001 primarily resulted from reduced margins associated with the mark-to-market of forward transactions in the current year versus the prior year. This reduction in margin is primarily the result of our electing hedge accounting on several of our transactions in 2002 utilizing our firm transportation capacity and fewer long-dated transactions utilizing our transportation capacity in place at the end of 2002 compared to 2001. Under hedge accounting, the margin to be realized on a transaction is recorded in the month the transportation capacity is used and under mark-to-market accounting, the anticipated margin on a transaction to be realized over the term of the transaction is recorded in the month of origination.

Marketing margins on NGLs averaged approximately $0.008 per gallon in the year ended December 31, 2002. This represents an increase as compared to the $0.005 per gallon realized in 2001. This is due to more favorable market conditions that were present in 2002 as compared to 2001.

In the year ended December 31, 2002, we expensed a total of $1.6 million for doubtful accounts, primarily due to the bankruptcy filing of a large mid-western co-op during the year. This compares to an expense of $2.7 million for doubtful accounts in 2001. These charges are not included in the calculation of the marketing margins and are reported in Selling and administrative expenses.

Plant and transportation operating expense increased by $6.0 million in the year ended December 31, 2002 compared to 2001. This increase was primarily due to additional leased compression, repair and maintenance and labor costs in the Powder River Basin coal bed development and higher property tax expenses at our plant facilities.

Oil and gas exploration and production expenses increased by $6.5 million in the year ended December 31, 2002 as compared to 2001. In our operating areas, the significant reduction in residue gas prices in the 2002 periods resulted in substantially lower severance tax expenses. These reductions were substantially offset by increased lease operating expenses, or LOE, in the Powder River Basin coal bed development. Overall, LOE averaged $0.42 per Mcf in the year ended December 31, 2002. LOE in the Powder River Basin coal bed development averaged $0.45 per Mcf in the year ended December 31, 2002. This represents increases of $0.06 per Mcf and $0.03 per Mcf from the comparable periods in 2001, respectively. The increases are substantially due to higher utility charges, increased use of leased generators, increased labor charges and prior period adjustments for operating supplies, utilities and technical supervision billed to us by the well operator. The increased LOE in 2002 were substantially offset by lower severance taxes resulting from the significant reduction in residue gas prices in 2002 as compared to 2001.

Selling and administrative expenses increased by $1.6 million in the year ended December 31, 2002 as compared to 2001, due to higher health insurance costs and higher compensation expenses.

Depreciation, depletion and amortization increased by $12.8 million in the year ended December 31, 2002 as compared to 2001 primarily as a result of our increasing operations in the Powder River Basin coal bed methane development.

The provision for income taxes increased to a 37.3% effective rate for the year ended December 31, 2002 from 37.1% in 2001. This change is due to increased sales of third-party product in states with higher corporate tax rates and in Canada. We expect that this increase in our effective tax rate will continue in future periods.

*Cash Flow Information*

Cash flows from operating activities decreased by $22.1 million in the year ended December 31, 2002 compared to 2001. This reduction was primarily due to a decrease in net income in 2002 compared to the prior year and the timing of cash receipts and payables.

Cash flows used in investing activities decreased by $25.9 million in the year ended December 31, 2002 compared to 2001. This decrease was primarily due to a reduction in capital expenditures.

Cash flows used in financing activities increased by $3.6 million in the year ended December 31, 2002 compared to 2001. This increase was due to the application of the proceeds received in the sale of our Toca Processing facility in 2002 to reduce the amounts outstanding under our Revolving Credit Facility.

*Other Information*

*Preferred Stock Redemption.* In December 2002, we redeemed all the remaining shares of our $2.28 cumulative preferred stock currently outstanding, at a liquidation preference of $25.00 per share plus accrued and unpaid dividends, for a total of approximately $14.0 million. The capitalized offering costs of $688,000 associated with the redeemed preferred stock are reflected as a special dividend to preferred shareholders in 2002 and reduced earnings available to common shareholders by approximately $0.02 per common share.

*Toca Processing Facility.* In June 2002, we entered into an agreement for the sale of our Toca processing facility in Louisiana. This sale closed in September 2002. The sale price was $32.2 million, subject to accounting adjustments, and resulted in a pre-tax loss of approximately $448,000. The purchase price included a natural gas processing plant with a capacity of 160 million cubic feet per day and a fractionator that can separate 14,200 barrels per day of mixed natural gas liquids into propane, normal butane, iso-butane and natural gasoline. The sale also includes NGL storage as well as truck, rail and barge loading facilities, which support the complex. During the year ended December 31, 2002, this facility generated net after-tax earnings of approximately $683,000, or $.02 per share of common stock, respectively. We believe the results from this facility are immaterial for separate presentation as a discontinued operation. Approximately $15.0 million of the proceeds received from this asset sale were initially used to reduce amounts outstanding on our Revolving Credit Facility. At December 31, 2002, the remaining amount of $17.2 million was on deposit with a trustee in anticipation of the completion of a like-kind exchange transaction and was reflected on the Consolidated Balance Sheet under the caption Other current assets. These funds, along with additional amounts drawn on our Revolving Credit Facility, were used in a January 2003 acquisition of several gathering systems.

*Bethel Treating Facility.* In December 2000, we signed an agreement for the sale of all the outstanding stock of our wholly owned subsidiary, Pinnacle Gas Treating, Inc., or Pinnacle, for $38.0 million. The only asset of this subsidiary was a 300 MMcf per day treating facility and 86 miles of associated gathering assets located in east Texas. The sale closed in January 2001 and resulted in a net pre-tax gain for financial reporting purposes of $12.1 million in the first quarter of 2001.

*Transactions with Officers.* In October 2002, we granted options covering a total of 169,500 shares of our common stock to our ten executive officers. The exercise price with respect to these options is $32.95 per share. In accordance with the terms of the stock option plan pursuant to which the options were granted, the option price is the average closing price for our common stock for the ten trading days prior to the grant.

In June 2001, the Compensation and Nominating Committee recommended, and the board approved, retention bonuses totaling $820,000 for nine of our executive officers. These bonuses were contingent upon the officer not voluntarily terminating employment for one year following the hiring of a new Chief Executive Officer and President. These bonuses were paid on November 1, 2002.

In 1989, we loaned to our officers at that time, an amount sufficient to exercise their options under our stock option plans. The loans and accrued interest were to be forgiven if the officer remained employed by us for specified time periods and upon a resolution of the board of directors. During 2002, we forgave loans totaling $703,000 related to the exercise of options covering 62,500 shares of common stock. After giving effect to the forgiveness, a loan in the amount of $134,000 related to the exercise of options covering 12,500 shares of common stock remains outstanding. Pursuant to the terms of an agreement entered into in the second quarter of 2001, the remaining loan will be forgiven in May 2003. In prior years, we have reserved for the forgiveness of these loans.

**Year ended December 31, 2001 compared to year ended December 31, 2000**
**(000s, except per share amounts and operating data)**

| | Year Ended December 31, | | Percent |
|---|---|---|---|
| | 2001 | 2000 | Change |
| **Financial results:** | | | |
| Revenues | $ 3,353,162 | $ 3,280,091 | 2 |
| Gross profit | 200,780 | 149,155 | 35 |
| Net income (loss) | 95,637 | 56,108 | 70 |
| Income (loss) per share of common stock | 2.59 | 1.42 | 82 |
| Income (loss) per share of common stock - assuming dilution | 2.48 | 1.39 | 78 |
| Net cash provided by operating activities | $ 153,267 | $ 116,262 | 32 |
| **Operating data:** | | | |
| Average gas sales (MMcf/D) | 1,961 | 1,835 | 7 |
| Average NGL sales (MGal/D) | 2,347 | 3,085 | (24) |
| Average gas prices ($/Mcf) | $ 3.97 | $ 3.90 | 2 |
| Average NGL prices ($/Gal) | $ .49 | $ .52 | (6) |

Net income increased $39.5 million for the year December 31, 2001 compared to 2000. The increase in net income was primarily attributable to higher gas prices in 2001 compared to the prior year, increased production from the Powder River Basin coal bed methane development, and improved results from our marketing segment.

Revenues from the sale of gas increased $221.0 million to $2,849.1 million in the year ended December 31, 2001 compared to 2000. This increase was primarily due to an improvement in product prices and to a lesser extent from an increase in sales of natural gas purchased from third parties. Average gas prices realized by us increased $0.07 per Mcf to $3.97 per Mcf in the year ended December 31, 2001 compared to 2000. Included in the realized gas price were approximately $9.3 million of gains recognized in the year ended December 31, 2001 related to futures positions on equity gas volumes. Average gas sales volumes increased 125 MMcf per day to 1,960 MMcf per day in the year ended December 31, 2001compared to 2000. This increase in sales volume was primarily due to an increase in the sale of third- party product.

Revenues from the sale of NGLs decreased approximately $166.9 million in the year ended December 31, 2001 compared to 2000. This decrease was due to a reduction in sales volume and a decrease in product prices. Average NGL prices realized by us decreased $0.03 per gallon to $0.49 per gallon in the year ended December 31, 2001 compared to 2000. Included in the realized NGL price were approximately $2.1 million of gains recognized in the year ended December 31, 2001 related to futures positions on equity NGL volumes. Average NGL sales volumes decreased 735 MGal per day to 2,350 MGal per day in the year ended December 31, 2001 compared to 2000. This decrease was primarily due to an intentional reduction in the sale of third-party product as these types of sales were generating minimal margins. Also contributing to the reduction in overall sales volume was a decrease in the sale of product produced at our facilities as we did not recover ethane for a portion of 2001 due to low ethane prices.

Product purchases increased by $1.4 million in the year ended December 31, 2001 compared to 2000. Overall, combined product purchases as a percentage of sales of all products decreased to approximately 91% in the year ended December 31, 2001 from 93% in 2000. The decrease in the product purchase percentage resulted from improved marketing margins and the intentional reduction in the sale of third-party NGL products.

Marketing margins on residue gas averaged $0.06 per Mcf in 2001. This represented a significant increase as compared to the $0.02 per Mcf marketing margin realized during 2000. The increase in margin for the year ended December 31, 2001 primarily resulted from volatility in gas prices, gains realized on our firm transportation capacity and from the mark-to-market of transactions utilizing a portion of this firm transportation capacity primarily during 2002 and the mark-to-market of storage transactions for the winter season ending in March 2002. Under mark-to-market accounting, which we adopted on January 1, 2001, the margin to be realized over the term of the transaction is recorded in the month of origination. Of the total margin earned in the marketing segment of $47.6 million, approximately $19.9 million resulted from the portion of sales transactions beyond 2001 including the marking to market at December 31, 2001 of our derivative positions as required by SFAS No. 133. This margin is included in the financial statement caption Non-cash change in fair value of derivatives.

Marketing margins on NGLs averaged approximately $0.005 per gallon in the year ended December 31, 2001. This represents a decrease as compared to the margin realized during 2000 of $0.007 per gallon. This decrease has resulted in our decision to intentionally reduce the sale of third-party NGL products.

On December 2, 2001, Enron Corp. and many of its affiliates and subsidiaries filed a petition for bankruptcy protection under Chapter 11 of the Bankruptcy code in the Southern District of New York. At the time of Enron's filing, our exposure to it totaled approximately $2.7 million. This amount includes the net exposure from physical gas transactions of $100,000, which is comprised of physical gas sales of $8.4 million and physical gas purchases of $8.3 million. We have in place a netting agreement with Enron for the purchase and sale of physical gas. Although bankruptcy courts have upheld similar netting agreements in the past, we can provide no assurance that our agreement will not be challenged or the outcome of any challenge. The remaining $2.6 million of net exposure is under a Master Swap Agreement related to derivative transactions. As a result, we incurred an additional charge to income of $2.7 million in 2001. This exposure to Enron is not included in the calculation of the marketing margins and is primarily reported in Selling and administrative expenses.

Plant and transportation operating expense increased $5.6 million in 2001 compared to 2000. This increase was primarily due to additional leased compression in the Powder River Basin coal bed development and higher fuel costs at our plant facilities.

Oil and gas exploration and production expenses increased by $8.0 million in 2001 as compared to 2000. The increase in the period is primarily as a result of our overall increasing operations in the Powder River Basin coal bed methane development.

Depreciation, depletion and amortization increased by $6.2 million for the year ended December 31, 2001 as compared to 2000, primarily as a result of our increasing operations in the Powder River Basin coal bed methane development.

Extraordinary charge for early extinguishment of debt decreased for the year ending December 31, 2001 as compared to 2000 as a result of an after-tax charge of $1.7 million incurred in third quarter of 2000. In September 2000, we prepaid $27.0 million of outstanding indebtedness originally due to be paid in November 2005, with funds available under our Revolving Credit Facility. In connection with this prepayment, we paid a pre-tax make-whole payment of approximately $2.0 million and expensed capitalized fees of approximately $752,000.

*Other Information*

*Preferred Stock Redemption.* On November 12, 2001, we issued a notice of redemption for approximately 800,000 shares of our $2.28 cumulative preferred stock at its liquidation preference. This totaled $20.6 million including accrued and unpaid dividends. The redemption date was December 10, 2001 and was funded with amounts available under our Revolving Credit Facility. The pro rata capitalized offering costs of $900,000 associated with the redeemed preferred stock were reflected as a special dividend to preferred shareholders in 2001 and, accordingly, reduced earnings available to common shareholders by approximately $0.03 per common share.

*Bethel Treating Facility.* In December 2000, we signed an agreement with Anadarko Petroleum Corporation for the sale of all the outstanding stock of our wholly owned subsidiary, Pinnacle, for $38.0 million. The only asset of this subsidiary was a 300 MMcf per day treating facility and 86 miles of associated gathering assets located in east Texas. The sale closed in January 2001 and resulted in an approximate pre-tax gain for financial reporting purposes of $12.1 million in the first quarter of 2001.

*Arkoma.* In August 2000, we sold our Arkoma Gathering System in Oklahoma for gross proceeds of $10.5 million. This sale resulted in a pre-tax gain of $3.9 million.

*Western Gas Resources-California, Inc.* In January 2000, we sold all the outstanding stock of our wholly owned subsidiary, WGR-California, for $14.9 million. The only asset of this subsidiary was a 162-mile pipeline in the Sacramento Basin of California. WGR-California acquired the pipeline through the exercise of a purchase option in a transaction that closed immediately prior to the sale by us of WGR-California. We recognized a pre-tax gain on the sale of approximately $5.4 million in the first quarter of 2000.

The proceeds from these sales were used to reduce borrowings outstanding on the Revolving Credit Facility.

*Westana.* In February 2000, we acquired the remaining 50% interest in the Westana Gathering Company for a net purchase price of $9.8 million. The results from our ownership through February 2000 of a 50% equity interest in the Westana Gathering Company are reflected in revenues in Other on the Consolidated Statement of Operations. Beginning in March 2000, the results of these operations have been fully consolidated and are included in Revenues and Costs and expenses. Additionally, in March 2000, our investment in the Westana Gathering Company was reclassified from Other assets to Property and equipment.

*Granger Complex.* In May 2001, we acquired the remaining 50% interest in a portion of the Bird Canyon gathering system serving the Granger complex for a net purchase price of $5.9 million in cash and the settlement of previously disclosed litigation. In September 2001, we signed an agreement with Questar Gas Management Company for the sale of a 50% interest in a segment of the Bird Canyon gathering system along with associated field compression for $5.2 million. This sale closed in October 2001. These assets were reclassified on the Consolidated Balance Sheet to Assets held for sale at September 30, 2001, and a $400,000 pre-tax loss on the excess of the net book value over the sales price of these assets was recognized in the third quarter of 2001.

Also in October 2001, both Questar and Western contributed their respective interests in the Bird Canyon system along with additional field compression and gathering dedications for gas produced along the Pinedale Anticline to a newly formed joint venture named Rendezvous. Each company owns a 50% interest in Rendezvous, and we serve as field operator of its systems. Our 50% interest in Rendezvous is accounted for under the equity method.

*Critical Accounting Policies*

The application of accounting policies is an important process that has developed as our business activities have evolved and as accounting rules have developed. Accounting rules generally do not involve a selection among alternatives, but involve an interpretation and implementation of existing rules, and the use of judgment, to the specific set of circumstances existing in our business. We make every effort to properly comply with all applicable rules on or before their adoption, and we believe the proper implementation and consistent application of the accounting rules is critical. Our critical accounting policies and estimates are discussed below. For further details on our accounting policies, and the estimates, assumptions and judgments we use in applying these policies and a discussion of new accounting rules, see Note 2 of the Notes to Consolidated Financial Statements.

*Use of Estimates.* The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the amounts reported for assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the amounts reported for revenues and expenses during the reporting period. These estimates are evaluated on an ongoing basis, utilizing historical experience, consultation with experts and other methods considered reasonable in the particular circumstances. However, actual results may differ significantly from the estimates used. Any effects on our business, financial position or results of operations resulting from revisions to these estimates will be recorded in the period in which the facts that necessitate a revision become known.

*Property and Equipment.* Our property and equipment is recorded at the lower of cost, including capitalized interest, or estimated realizable value. Interest incurred during the construction period of new projects is capitalized and amortized over the life of the associated assets.

Depreciation on these assets is provided using the straight-line method based on the estimated useful life of each facility which ranges from three to 35 years. Useful lives are determined based on the shorter of our estimate of the life of the equipment or our estimate of the reserves serviced by the equipment. Among other factors, the estimates consider our experience with similar assets and technical analysis of the reserves. The cost of acquired gas purchase contracts is amortized using the straight-line method or units of production. If the actual lives of the equipment or the reserves serviced by the equipment were less than we originally estimated, we may be required to record a loss upon retirement of a specific asset.

*Oil and Gas Properties and Equipment.* We follow the successful efforts method of accounting for oil and gas exploration and production activities. Acquisition costs, development costs and successful exploration costs are capitalized when incurred. Exploratory dry hole costs, lease rentals and geological and geophysical costs are charged to expense as incurred. Upon surrender of undeveloped properties, the original cost is charged against income. Producing properties and related equipment are depleted and depreciated by the units-of-production method based on estimated proved reserves. The unit of production method is sensitive to the determination of proved reserves. We utilize technical analysis and outside expertise annually to determine the reserves associated with our oil and gas properties. To the extent the reserves are modified based on this review, the depletion determined under the units of production method will be increased or decreased on a prospective basis.

*Impairment of Long-Lived Assets.* If changes in the expected performance of an asset occur, or if overall economic conditions warrant, we will review our assets to determine their economic viability. This review is completed at the plant facility, the related group of plant facilities or the oil and gas producing property level. In order to determine whether an impairment exists, we compare the net book value of the asset to the estimated fair market value or the undiscounted expected future net cash flows, determined by applying future prices estimated by management over the shorter of the lives of the facilities or the reserves supporting the facilities. If an impairment exists, write-downs of assets are based upon expected future net cash flows discounted using an interest rate commensurate with the risk associated with the underlying asset. This analysis is sensitive to, among other things, management's expectation of commodity prices, operating costs, drilling plans and production rates.

*Identification of Derivatives and Mark to Market Valuations.* The determination of which contractual instruments meet the definition of a derivative under accounting rules is subject to differing interpretations as is the valuation of those derivatives. Management uses its judgment to analyze all contracts to determine whether or not they qualify as derivatives and to determine their value. Specific areas in which management's judgment is required includes identifying contracts meeting the criteria for exclusions from derivatives treatment, market liquidity, and market valuation. This analysis is sensitive to commodity prices, outside market factors and management's intent upon entering into these contracts.

*Significant Risks.* We are subject to a number of risks inherent in the industry in which we operate, including price volatility, counter party credit risk, the success of our drilling programs and other gas supply. Our financial condition and results of operations will depend significantly upon the prices we receive for gas and NGLs. These prices are subject to fluctuations in response to changes in supply and demand and a variety of additional factors that are beyond our control. In addition, we must continually connect new wells to our gathering systems in order to maintain or increase throughput levels to offset natural declines in dedicated volumes. The number of new wells drilled will depend upon, among other factors, prices for gas and oil, the drilling budgets of third-party producers, the energy policy of the federal government and the availability of foreign oil and gas, none of which are within our control.

*Recently Issued Accounting Pronouncements.* We continually monitor and revise our accounting policies as new rules are issued. At this time, there are several new accounting pronouncements that have recently been issued, but not yet adopted, which will have an impact on our accounting when these rules become effective in 2003. See further discussion in Note 2 – Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements.

*Business Strategy*

Maximizing the value of our existing core assets is the focal point of our business strategy. Our core assets are our fully integrated upstream and midstream assets in the Powder River and Green River Basins in Wyoming and our midstream operations in west Texas and Oklahoma. Our long-term business plan is to increase shareholder value by: (i) doubling proven reserves and equity production of natural gas from the levels achieved in 2001over a three to five year period; (ii) meeting or exceeding throughput projections in our midstream operations; and (iii) optimizing annual returns.

*Liquidity and Capital Resources*

Our sources of liquidity and capital resources historically have been net cash provided by operating activities, funds available under our financing facilities and proceeds from offerings of debt and equity securities. In the past, these sources have been sufficient to meet our needs and finance the growth of our business. We can give no assurance that the historical sources of liquidity and capital resources will be available for future development and acquisition projects, and we may be required to seek alternative financing sources. Product prices, sales of inventory, the volumes of natural gas processed by our facilities, the volume of natural gas produced from our producing properties, the margin on third-party product purchased for resale, as well as the timely collection of our receivables will all affect future net cash provided by operating activities. Additionally, our future growth will be dependent upon obtaining additions to dedicated plant reserves, acquisitions, new project development, marketing results, efficient operation of our facilities and our ability to obtain financing at favorable terms.

During the past several years, although some of our plants have experienced declines in dedicated reserves, overall we have been successful in connecting additional reserves to more than offset the natural declines. During 2002, some producers in the Rocky Mountain region have curtailed existing production or delayed their drilling programs due to lower prices resulting from limited transportation capacity out of the region. The overall level of drilling will depend upon, among other factors, the prices for oil and gas, the drilling budgets of third-party producers, availability of transportation capacity to market centers, the energy and environmental policy and regulation by governmental agencies, and the availability of foreign oil and gas, none of which is within our control. There is no assurance that we will continue to be successful in replacing the dedicated reserves processed at our facilities. Any prolonged reduction in prices for natural gas and NGLs may depress the levels of exploration, development and production by third parties and us. Lower levels of these activities could result in a corresponding decline in the demand for our gathering, processing and treating services. A reduction in any of these activities could have a material adverse effect on our financial condition and results of operations.

We believe that the amounts available to be borrowed under the Revolving Credit Facility, together with net cash provided by operating activities, will provide us with sufficient funds to connect new reserves, maintain our existing facilities, complete our current capital expenditure program and make any scheduled debt principal payments through 2003. We have from time to time renegotiated the Revolving Credit Facility to extend the maturities of the facility, and we intend to re-syndicate this facility and extend its maturity during the first quarter of 2003. This new facility will reflect the current bank market and will likely result in a higher interest rate. Depending on the timing and the amount of our future projects, and our ability to renegotiate the facility, we may be required to seek additional sources of capital. Our ability to secure such capital is restricted by our financing facilities, although we may request additional borrowing capacity from our lenders, seek waivers from our lenders to permit us to borrow funds from third parties, seek replacement financing facilities from other lenders, use stock as a currency for acquisitions, sell existing assets or a combination of alternatives. While we believe that we would be able to secure additional financing, if required, we can provide no assurance that we will be able to do so or as to the terms of any additional financing. We also believe that cash provided by operating activities and amounts available under the Revolving Credit Facility will be sufficient to meet scheduled principal repayments during 2003 of $43.3 million under the Master Shelf Agreement and our preferred stock dividend requirements during 2003 of approximately $7.2 million.

We have effective shelf registration statements filed with the SEC for an aggregate of $200 million of debt securities and preferred stock, along with the shares of common stock, if any, into which those securities are convertible, and $62 million of debt securities, preferred stock or common stock. These shelf registrations allow us to access the debt and equity markets without the requirement of further SEC review.

Our sources and uses of funds for the year ended December 31, 2002 are summarized as follows (dollars in thousands):

| | |
|---|---|
| **Sources of funds:** | |
| Borrowings under the Revolving Credit Facility | $ 994,545 |
| Proceeds from the dispositions of property and equipment | 34,865 |
| Net cash provided by operating activities | 131,136 |
| Proceeds from exercise of common stock options | 6,489 |
| Total sources of funds | $ 1,167,035 |
| **Uses of funds:** | |
| Payments related to long-term debt (including debt issue costs) | $ 1,001,404 |
| Capital expenditures | 125,600 |
| Preferred dividends paid | 8,504 |
| Common dividends paid | 6,603 |
| Redemption of $2.28 Cumulative Perpetual Preferred Stock | 12,607 |
| Contributions to equity investees | 15,037 |
| Total uses of funds | $ 1,169,755 |

***Capital Investment Program.*** Our capital expenditures totaled approximately $140.6 million during 2002 with approximately 80% invested in the Rocky Mountain region. Overall, capital expenditures in 2002 consisted of the following: (i) approximately $60.0 million related to gathering, processing, treating and pipeline assets, including $7.4 million for maintaining existing facilities; (ii) approximately $70.7 million related to exploration and production and lease acquisition activities; (iii) approximately $4.0 million for information technology; and (iv) approximately $5.9 million for capitalized overhead and interest. Overall, capital expenditures in the Powder River Basin coal bed methane development and in the Green

River Basin in southwest Wyoming operations represented 57% and 20%, respectively, of the total capital expenditures in 2002.

In 2003, we anticipate capital expenditures of approximately $182.3 million. Overall, the 2003 capital budget consists of the following: (i) approximately $58.2 million related to gathering, processing, treating and pipeline assets, including $11.4 million for maintaining existing facilities; (ii) approximately $74.9 million related to exploration and production and lease acquisition activities; (iii) $37.1 million for the acquisition of 18 gathering systems which closed in January 2003; (iv) approximately $4.3 million for information technology and other items and (v) $7.8 million for capitalized interest and overhead. Overall, capital expenditures in the Powder River Basin coal bed methane development and in southwest Wyoming operations represent 37% and 45%, respectively, of the total 2003 budget. Due to drilling and regulatory uncertainties that are beyond our control, we can make no assurance that our capital budget for 2003 will not change. We anticipate that funds for the 2003 capital budget will be provided primarily by internally generated cash flow, from the proceeds from the sale of our Toca facility in the fourth quarter of 2002 and from amounts available under our Revolving Credit Facility. This budget may be further increased to provide for acquisitions if approved by our board of directors.

*Contractual Commitments and Obligations*

*Contractual Cash Obligations.* A summary of our contractual cash obligations as of December 31, 2002 is as follows (dollars in thousands):

| | | Payments by Period | | | |
|---|---|---|---|---|---|
| Type of Obligation | Total Obligation | Due in 2003 | Due in 2004 – 2005 | Due in 2006 – 2007 | Due Thereafter |
| Guarantee of Fort Union Project Financing | $ 6,302 | $ 478 | $ 1,059 | $ 1,224 | $ 3,541 |
| Operating Leases | 61,686 | 12,902 | 18,884 | 16,874 | 13,026 |
| Firm Transportation Capacity and Gathering Agreements | 258,615 | 30,652 | 58,394 | 56,988 | 112,581 |
| Firm Storage Capacity Agreements | 28,633 | 5,240 | 7,577 | 5,365 | 10,451 |
| Long-term Debt | 359,934 | 43,334 | 141,600 | 20,000 | 155,000 |
| Total Contractual Cash Obligations | $ 715,170 | $ 92,606 | $ 227,514 | $ 100,451 | $ 294,599 |

*Guarantee of Fort Union Project Financing.* In 1998, we joined with other industry participants to form Fort Union to construct a 106-mile long, 24-inch gathering pipeline and treater to gather and treat natural gas in the Powder River Basin in northeast Wyoming. We own a 13% equity interest in Fort Union and are the construction manager and field operator. Construction of the gathering header and treating system was project financed by Fort Union and required a cash investment by us of approximately $900,000. In 2001, an expansion of Fort Union was completed. The expansion costs totaled approximately $22.0 million and were also project financed by Fort Union. This debt is amortizing on an annual basis and is scheduled to be fully paid in 2009. In 2001, we invested approximately $500,000 as an equity contribution to Fort Union in conjunction with the project financing. All participants in Fort Union have guaranteed Fort Union's payment of the project financing on a proportional basis, resulting in our guarantee of $6.3 million of the debt of Fort Union at December 31, 2002. This guarantee is not reflected on our Consolidated Balance Sheet.

*Operating Leases.* In the ordinary course of our business operations, we enter into operating leases for office space, office equipment, communication equipment and transportation equipment. In addition, primarily to support our growing development in the Powder River coal bed development, we have entered into operating leases for compression equipment. Payments made on these leases are a component of operating expenses and are reflected on the Consolidated Statement of Operations and, as operating leases, are not reflected on our Consolidated Balance Sheet. As of December 31, 2002, we had leased a total of 124 compression units. These leases have terms ranging from two to ten years with return or fair market purchase options available at various times during the lease. If we were to exercise the early buyout options on all the leased equipment, these purchase options would require the capital expenditure of approximately $32.6 million between the years of 2007 and 2011. At December 31, 2002, we had four compressor units under an interim leasing agreement. These compressors will be added to the existing lease arrangements when the equipment is installed and in service.

In August 2002, we entered into a seven year and nine month agreement for the lease of approximately 85,000 square feet of office space in Denver, Colorado. The cumulative lease payments over the term of this agreement, which begins upon occupancy, will total approximately $10.7 million. Our corporate offices were relocated to this space in March 2003. We also entered into a ten-year agreement effective in January 2003 for the lease of approximately 26,000 square feet of office space in

Gillette, Wyoming for our Wyoming field operations. The cumulative lease payments over the term of this agreement will total approximately $3.0 million. Neither of these leases is included in the table presented above since neither was in effect at December 31, 2002.

*Firm Transportation Capacity and Gathering Agreements.* Access to firm transportation is also a significant element of our business strategy. Firm transportation ensures that our equity production has access to downstream markets and allows us to capture incremental profit when pricing differentials between physical locations occur. As of December 31, 2002, we had contracts for approximately 674 MMcf per day of firm transportation. This amount represents our total contracted amount on many individual pipelines. In many cases it is necessary to utilize sequential pipelines to deliver gas into a specific sales market. In total, we have the capacity to transport 173 MMcf per day of gas from the Rocky Mountain area to the Mid-Continent. This utilizes a total of approximately 408 MMcf per day of firm capacity on four separate pipelines. The total rate to transport this gas to the Mid-Continent approximates $0.35 per Mcf. Our remaining firm capacity consists of 146 MMcf per day to markets within the Rocky Mountains and 120 MMcf per day contracted in various other markets throughout the country. In addition, we hold 83 MMcf per day of firm gathering capacity on the Fort Union gathering line.

A portion of this firm transportation capacity was contracted for use in our Marketing operations. For example, our Marketing segment purchases gas in the Rocky Mountain region, transports this gas utilizing its 56 MMcf per day of our firm transportation capacity to the Mid-Continent, and resells the gas to various markets. During the 2002, these types of transactions have been profitable as the price difference, or basis, between the Rocky Mountain and Mid-Continent regions has exceeded the cost of transportation. Historically, to the extent these transportation contracts were acquired for our Marketing segment, they were derivative contracts as defined by SFAS No. 133 and are marked to market. On October 1, 2002, the FERC's policy on capacity release expired. After that date, companies are no longer able to re-market transportation capacity at rates which exceed the maximum allowable rate permitted by the pipelines' tariff. On some pipelines, this reduces our ability to liquidate our position. Accordingly, the transportation contracts on these specific pipelines are no longer considered derivatives under SFAS No. 133 and will not be marked to market. On occasion we may elect to hedge the cash flows resulting from transactions utilizing this transportation capacity. To the extent of these hedges the transactions are classified as cash flow hedges.

We expect that the fixed fees associated with our contracts for firm transportation capacity during 2003 will average approximately $0.16 per Mcf per day. The associated contract periods range from one month to fourteen years. Under firm transportation contracts, we are required to pay the fees associated with these contracts whether or not the transportation is used.

*Firm Storage Capacity Agreements.* We customarily store gas in underground storage facilities to ensure an adequate supply for long-term sales contracts and to capture seasonal price differentials. As of December 31, 2002, we had contracts in place for approximately 20.2 Bcf of storage capacity at various third-party facilities. The fees associated with these contracts during 2003 will average $0.29 per Mcf of annual capacity. The associated contract periods have an average term of seventeen months. At December 31, 2002, we held gas in our contracted storage facilities and in imbalances of approximately 15.1 Bcf at an average cost of $2.72 per Mcf compared to 16.9 Bcf at an average cost of $2.39 per Mcf at December 31, 2001. These positions are for storage withdrawals within the next fifteen months. At the time that we place product into storage, we contract for the sale of that product, physically or financially, and do not speculate on the future value of the product. We have also entered into a precedent agreement for 2.4 Bcf of annual capacity, for a term of ten years, for storage in a facility, which is not yet completed. We anticipate the completion of the construction of this facility in 2004. When the facility is completed, we will enter into a storage agreement.

From time to time, we lease NGL storage space at major trading locations in order to store products for resale during periods when prices are favorable and to facilitate the distribution of products. At December 31, 2002, we held NGLs in storage at various third-party facilities of 2,755 MGal, consisting primarily of propane and normal butane, at an average cost of $0.25 per gallon compared to 5,665 MGal at an average cost of $0.33 per gallon at December 31, 2001.

*Long-term Debt*

*Revolving Credit Facility.* The Revolving Credit Facility is with a syndicate of banks and provides for a maximum borrowing commitment of $250 million consisting of an $83 million 364-day Revolving Credit Facility, or Tranche A, which matures on April 24, 2003, and a $167 million Revolving Credit Facility, or Tranche B, which matures on March 31, 2004. At December 31, 2002, $96.6 million was outstanding under this facility. The Revolving Credit Facility bears interest at certain spreads over the Eurodollar rate, or the greater of the Federal Funds rate or the agent bank's prime rate. We have the option to determine which rate will be used. We also pay a facility fee on the commitment. The interest rate spreads and facility fee are adjusted based on our debt to capitalization ratio and range from .75% to 2.00%. At December 31, 2002, the interest rate payable on borrowings under this facility was approximately 2.6%. We are required to maintain a total debt to capitalization ratio of not more than 55%, and a senior debt to capitalization ratio of not more than 35%. The agreement also requires a quarterly test of the ratio of EBITDA (excluding some non-recurring items) for the last four quarters, to interest and dividends on preferred stock for the same period. This ratio must exceed 3.25 to 1.0. This facility also limits our ability to enter into operating leases and sale-leaseback transactions. This facility is guaranteed and secured via a pledge of the stock of all of our material subsidiaries.

We intend to enter into a new revolving loan arrangement in the first quarter of 2003 to replace the existing Revolving Credit Facility. Our practice has been to replace our existing facility approximately one year prior to its final maturity date to ensure adequate sources of capital for our operations. As proposed, this new facility will reflect the current bank market with the interest rate spreads and facility fee adjusted based on our debt to capitalization ratio and ranging from 1.50% to 2.25%. While we believe that we will be able to secure a new revolving loan agreement, we can provide no assurance as to the pricing, terms and covenants of this new agreement.

*Master Shelf Agreement.* In December 1991, we entered into a Master Shelf Agreement with The Prudential Insurance Company of America. Amounts outstanding under the Master Shelf Agreement at December 31, 2002 are as indicated in the following table (dollars in thousands):

| Issue Date | Amount | Interest Rate | Final Maturity | Principal Payments Due |
|---|---|---|---|---|
| October 27, 1992 | $ 8,333 | 7.99% | October 27, 2003 | single payment at maturity |
| December 27, 1993 | 25,000 | 7.23% | December 27, 2003 | single payment at maturity |
| October 27, 1994 | 25,000 | 9.24% | October 27, 2004 | single payment at maturity |
| July 28, 1995 | 50,000 | 7.61% | July 28, 2007 | $10,000 on each of July 28, 2003 through 2007 |
| | $108,333 | | | |

Under our agreement with Prudential, we are required to maintain a minimum tangible net worth equal to the sum of $300 million plus 50% of consolidated net earnings earned from January 1, 1999 plus 75% of the net proceeds of any equity offerings after January 1, 1999, a total debt to capitalization ratio of not more than 55% and a senior debt to capitalization ratio of not more than 35%. This agreement also requires a quarterly test of the ratio of EBITDA (excluding some non-recurring items) for the last four quarters, to interest for the same period. This ratio must exceed 3.25 to 1.0. The agreement also provides for a maximum ratio of senior debt to EBITDA of 4.0 to 1.0. In addition, this agreement contains a calculation limiting dividends and other restricted payments including preferred stock redemptions. Under this limitation, approximately $78.3 million was available for restricted payments at December 31, 2002. This facility also limits our ability to enter into operating leases and sale-leaseback transactions. The agreement provides for an annual fee of 0.50% on the amounts outstanding on the Master Shelf Agreement if we have not received an implied investment grade rating on our senior unsecured debt from Moody's Investors Service or Standard & Poor's and if the ratio of adjusted consolidated debt to EBITDA (as defined in the shelf) for the period of four fiscal quarters most recently ended exceeds 3.00 to 1.0. Under these terms, this fee is not currently being assessed. Borrowings under the Master Shelf Agreement are guaranteed by, and secured via, a pledge of the stock of all of our material subsidiaries.

In October 2002, we funded a required principal repayment under the Master Shelf Agreement of $8.3 million with funds available under the Revolving Credit Facility. During 2003, we are required to make principal payments totaling $43.3 million. We intend to fund these with amounts available under the Revolving Credit Facility.

On January 17, 2003, we borrowed an additional $25.0 million under the Master Shelf Agreement. The note bears interest at 6.36% and will be due in a single payment on January 17, 2008. We have the option to prepay the amount in full, at par on January 18, 2005. The funds we received from this borrowing were used in connection with our acquisition of 18 gathering systems in January 2003.

*Senior Subordinated Notes.* In 1999, we sold $155.0 million of Senior Subordinated Notes in a private placement with a final maturity of 2009 due in a single payment which were subsequently exchanged for registered publicly tradeable notes under the same terms and conditions. The Subordinated Notes bear interest at 10% per annum and were priced at 99.225% to yield 10.125%. These notes contain covenants, which include limitations on debt incurrence, restricted payments, liens and sales of assets. Under the calculation limiting restricted payments, including common dividends and preferred stock redemptions, approximately $42.8 million was available at December 31, 2002. The Subordinated Notes are unsecured and are guaranteed on a subordinated basis by all our material subsidiaries. We incurred approximately $5.0 million in offering commissions and expenses, which were capitalized and are being amortized over the term of the notes.

*Covenant Compliance.* We were in compliance with all covenants in our debt agreements at December 31, 2002. Taking into account all the covenants contained in these agreements, we had approximately $115.0 million of available borrowing capacity at December 31, 2002. None of our current credit facilities includes covenant requirements or acceleration provisions based upon a change in our credit ratings. However, as proposed the new revolving loan arrangement that we expect to enter into will include a lien on our oil and gas properties that will spring into effect if the ratings on this specific loan are reduced to BB- or below by Standard & Poor's or to Ba3 or below by Moody's Investors Service.

*Redemption of Preferred Stock.* In December 2002, we redeemed all the remaining shares of our $2.28 cumulative preferred stock then outstanding, at a liquidation preference of $25.00 per share plus accrued and unpaid dividends, for a total of $14.0 million. This redemption was funded with amounts available under our Revolving Credit Facility.

*Environmental*

The construction and operation of our gathering systems, plants and other facilities used for the gathering, processing, treating or transporting of gas and NGLs are subject to federal, state and local environmental laws and regulations, including those that can impose obligations to clean up hazardous substances at our facilities or at facilities to which we send wastes for disposal. In most instances, the applicable regulatory requirements relate to water and air pollution control or waste management. We employ an environmental manager, a safety manager, four environmental engineers, three safety specialists and three regulatory compliance specialists to monitor environmental and safety compliance at our facilities. In addition, on an ongoing basis, the environmental engineers perform environmental assessments of our existing facilities. We believe that we are in substantial compliance with applicable material environmental laws and regulations. Environmental regulation can increase the cost of planning, designing, constructing and operating our facilities. We believe that the costs for compliance with current environmental laws and regulations have not had and will not have a material effect on our financial position or results of operations.

Prior to consummating any major acquisition, our environmental engineers perform audits on the facilities to be acquired. In conducting this audit on the gathering systems acquired from EPFS, in January 2003, we identified many well sites that include underground sump tanks, pits, or tinhorns that are not properly permitted according to Wyoming Oil and Gas Conservation Commission, or WYOGCC, regulations. We have reported these violations to WYOGCC and are providing it with our remediation plan. It is our intention to remove all these underground facilities over the next several months. Based on our discussions with the WOGCC, it is our belief that it will not pursue any type of fines or penalties from us related to these assets. We believe the cost of our remediation plan will approximate $1.5 million, and EPFS has established an escrow account in that amount to reimburse us for these and other costs. In addition, at the time of the acquisition, we obtained an insurance policy that we believe will cover any additional environmental issues that may be identified over the next three years associated with these assets, up to a total exposure of $5.0 million.

The Texas Council on Environmental Quality, which has authority to regulate, among other things, stationary air emissions sources, has created a committee to make recommendations to it regarding a voluntary emissions reduction plan for the permitting of existing "grand-fathered" air emissions sources within Texas. A "grand-fathered" air emissions source is one that does not need a state-operating permit because it was constructed prior to 1971. We operate a number of these sources within Texas, including portions of our Midkiff/Benedum, Gomez and Mitchell Puckett systems. In connection with a modernization program, which was completed in March 2002, we replaced the majority of our "grand-fathered" equipment in Texas. We believe that the potential cost of complying with these regulations for our remaining "grand-fathered" equipment will not have material adverse effect on our results of operations or financial position.

We anticipate that the trend in environmental legislation and regulation will continue to be toward stricter standards. Federal regulations regarding spill prevention and containment have recently been modified to establish a lower threshold of storage capacity of petroleum and petroleum by-products at a site for which a spill prevention plan is required. We are evaluating all our assets for compliance with this regulation and estimate that approximately 100 existing sites will need to be modified to meet the new requirements. We currently estimate our costs for compliance to be approximately $2.0 million. The new spill prevention plans must be in place for covered assets by April 2003. All modifications called for in those plans must be in place by August 2003. We are unaware of any other future environmental standards that are reasonably likely to be adopted that will have a material effect on our financial position or results of operations, but we cannot rule out that possibility.

We are in the process of voluntarily cleaning up substances at certain facilities that we operate. Our expenditures for environmental evaluation and remediation at existing facilities have not been significant in relation to our results of operations and totaled approximately $1.4 million for the year ended December 31, 2002, including approximately $587,000 in air emissions fees to the states in which we operate. Although we anticipate that such environmental expenses per facility will increase over time, we do not believe that such increases will have a material effect on our financial position or results of operations.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our commodity price risk management program has two primary objectives. The first goal is to preserve and enhance the value of our equity volumes of gas and NGLs with regard to the impact of commodity price movements on cash flow, net income and earnings per common share in relation to those anticipated by our operating budget. The second goal is to manage price risk related to our gas, crude oil and NGL marketing activities to protect profit margins. This risk relates to fixed price purchase and sale commitments, the value of storage inventories and exposure to physical market price volatility.

We utilize a combination of fixed price forward contracts, exchange-traded futures and options, as well as fixed index swaps, basis swaps and options traded in the over-the-counter, or OTC, market to accomplish these goals. These instruments allow us to preserve value and protect margins because corresponding losses or gains in the value of the financial instruments offset gains or losses in the physical market.

We use futures, swaps and options to reduce price risk and basis risk. Basis is the difference in price between the physical commodity being hedged and the price of the futures contract used for hedging. Basis risk is the risk that an adverse change in the futures market will not be completely offset by an equal and opposite change in the cash price of the commodity being hedged. Basis risk exists in natural gas primarily due to the geographic price differentials between cash market locations and futures contract delivery locations.

We enter into futures transactions on the New York Mercantile Exchange, or NYMEX, and through OTC swaps and options with various counter parties, consisting primarily of financial institutions and other natural gas companies. We conduct our standard credit review of OTC counter parties and have agreements with many of these parties that contain collateral requirements. We generally use standardized swap agreements that allow for offset of positive and negative exposures. OTC exposure is marked-to-market daily for the credit review process. Our OTC credit risk exposure is partially limited by our ability to require a margin deposit from our major counter parties based upon the mark-to-market value of their net exposure. We are subject to margin deposit requirements under these same agreements. In addition, we are subject to similar margin deposit requirements for our NYMEX counter parties related to our net exposures. Beginning in 2003, the prices for natural gas, crude oil and NGL products have increased significantly. For example, the NYMEX contract for March 2003 delivery of natural gas closed at $9.13 per MMbtu as compared to $2.39 per MMbtu for the March 2002 NYMEX contract. Primarily as a result of our equity hedge positions for natural gas and liquid products, we have posted margin totaling $29.8 million with various counter parties at March 3, 2003.

We continually monitor and review the credit exposure to our marketing counter parties. As prices have increased, throughout the winter of 2002 – 2003, we have become increasingly concerned with our counter party credit exposure. As a result, we have reduced our sales of third-party natural gas volumes to reduce our credit exposure. During 2002, we incurred a total expense of $1.6 million for uncollectible accounts. This represents 0.06% of our total consolidated revenues of $2.5 billion for the year ended December 31, 2002. Additionally, beginning in 2001, we became increasingly concerned with our credit exposure to our customers, primarily a category of our customers generally known as "energy merchants." Energy merchants create liquidity in the marketplace for natural gas transactions and have historically been some of our largest suppliers and customers. In order to minimize our credit exposures, we have utilized existing netting agreements to reduce our net credit exposure, established new netting agreements with additional customers, terminated several long-term marketing obligations, negotiated accelerated payment terms with several customers, and reduced the amount of credit which we make available to various customers. Although similar netting agreements have been upheld by bankruptcy courts in the past, if any of these customers with whom we have netting agreements were to file for bankruptcy, we can provide no assurance that our agreements will not be challenged or as to the outcome of any challenge.

We have identified one Master Swap Agreement containing ratings triggers. Under this agreement, either party may be required to post additional collateral in the event of a decrease in their current rating by Standard & Poor's or Moody's Investors Service. Based on our outstanding positions under this agreement and our counter party's credit rating at March 3, 2003, we were holding approximately $8.7 million of collateral.

The use of financial instruments may expose us to the risk of financial loss in some circumstances, including instances when (i) our equity volumes are less than expected, (ii) our customers fail to purchase or deliver the contracted quantities of natural gas or NGLs, or (iii) our OTC counter parties fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in these prices.

*Risk Policy and Control.* We control the extent of risk management and marketing activities through policies and procedures that involve the senior level of management. On a daily basis, our marketing activities are audited and monitored by our independent risk oversight department, or IRO. This department reports to the Chief Financial Officer, thereby providing a separation of duties from the marketing department. Additionally, the IRO reports monthly to the Risk Management Committee, or RMC. This committee is comprised of corporate managers and officers and is responsible for developing the policies and guidelines that control the management and measurement of risk. The RMC is also responsible for setting risk limits, including value-at-risk and dollar stop loss limits. Our board of directors approves the risk limit parameters and risk management policy.

*Hedge Positions.* As of March 12, 2003, we have hedged approximately 53% of our projected equity natural gas volumes and approximately 78% of our estimated equity production of crude oil, condensate, and NGLs. These contracts are designated and accounted for as cash flow hedges. As such, gains and losses related to the effective portions of the changes in the fair value of the derivatives are recorded in Accumulated other comprehensive income, a component of Stockholders' equity. Any gains or losses on these cash flow hedges are recognized in the Consolidated Statement of Operations through Product purchases when the hedged transactions occur. Gains or losses from the ineffective portions of changes in the fair value of cash flow hedges are recognized currently in earnings through Non-cash change in the fair value of derivatives. This ineffectiveness is primarily due to the use of crude oil swaps in hedging the variability in the sales price of butanes. During 2002, we recognized a total of $154,000 of loss from the ineffective portions of our hedges. Overall, our hedges are expected to continue to be "highly effective" under SFAS 133 in the future. In the fourth quarter of 2002, in order to properly align our hedged volumes of natural gas to our forecasted equity production for 2003, we discontinued hedge treatment on financial instruments for 6 MMcf per day. As a result, a pre-tax gain of $790,000 was reclassified into earnings in the fourth quarter of 2002 from other comprehensive income.

To qualify as cash flow hedges, the hedge instruments must be designated as cash flow hedges and changes in their fair value must correlate with changes in the price of the forecasted transaction being hedged so that our exposure to the risk of commodity price changes is reduced. To meet this requirement, we hedge both the price of the commodity and the basis between that derivative's contract delivery location and the cash market location used for the actual sale of the product. This structure attains a high level of effectiveness, insuring that a change in the price of the forecasted transaction will result in an equal and opposite change in the cash price of the hedged commodity. We utilize crude oil as a surrogate hedge for butanes. This typically results in an effective hedge as crude oil and butane prices historically have moved in tandem.

*Outstanding Equity Hedge Positions and the Associated Basis for 2003.* The following table details our hedge positions as of March 3, 2003. In order to determine the hedged price to the particular operating region, deduct the basis differential from the NYMEX price. The prices for NGLs do not include the cost of the hedges of approximately $930,000.

| Product | Quantity and NYMEX or Settlement Price | Hedge of Basis Differential |
|---|---|---|
| Natural gas | 52,000 MMbtu per day with an average price of $3.95 per MMbtu.<br><br>20,000 MMbtu per day with a minimum price of $3.50 per MMbtu and an average maximum price of $4.43/MMbtu. | Mid-Continent – 23,000 MMbtu per day with an average basis price of ($0.16) per MMbtu.<br><br>Permian – 5,000 MMbtu per day with an average basis price of ($0.1325) per MMbtu.<br><br>Rocky Mountain – 44,000 MMbtu per day with an average basis price of ($0.80) per MMbtu. |
| Crude Oil | 55,000 Barrels of crude oil per month with an average price of $26.02 per barrel. | Not Applicable |
| Butanes | 50,000 Barrels of crude oil per month. Floor at $24.00 per barrel. (Crude oil is used as a surrogate for butanes). | Not Applicable |
| Propane | 100,000 Barrels per month. Average minimum and maximum price of $0.37 per gallon and $0.50 per gallon, respectively. | Not Applicable |
| Ethane | 125,000 Barrels per month. Average minimum and maximum price of $0.25 per gallon and $0.37 per gallon, respectively. | Not Applicable |

Account balances related to equity and transportation hedging transactions at December 31, 2002 were $11.8 million in Current Assets from price risk management activities, $20.1 million in Current Liabilities from price risk management activities, ($3.1) million in Deferred income taxes payable, net, and a $5.4 million after-tax unrealized loss in Accumulated other comprehensive income, a component of Shareholders' Equity. Based on the commodity prices as of December 31, 2002, the after-tax loss of $5.4 million will be re-classified from Accumulated other comprehensive income to Product Purchases during the next twelve months.

*Natural Gas Derivative Market Risk.* As of December 31, 2002, we held a notional quantity of approximately 303 Bcf of natural gas futures, swaps and options extending from January 2003 to October 2006 with a weighted average duration of approximately six months. This was comprised of approximately 116 Bcf of long positions and 187 Bcf of short positions in these instruments. As of December 31, 2001, we held a notional quantity of approximately 439 Bcf of natural gas futures, swaps and options extending from January 2002 to October 2006 with a weighted average duration of approximately six months. This was comprised of approximately 199 Bcf of long positions and 240 Bcf of short positions in these instruments.

*Crude Oil and NGL Derivative Market Risk.* As of December 31, 2002, we held a notional quantity of approximately 275,940 MGal of crude oil and NGL futures, swaps and options extending from January 2003 to December 2003 with a weighted average duration of approximately six months. This was comprised of approximately 138,600 MGal of long positions and 137,340 MGal of short positions in these instruments. As of December 31, 2001, we held a notional quantity of approximately 131,124 MGal of crude oil and NGL futures, swaps and options extending from January 2002 to December 2002 with a weighted average duration of approximately six months. This was comprised of approximately 61,824 MGal of long positions and 69,300 Mgal of short positions in these instruments.

As of December 31, 2002, we did not hold any NGL futures, swaps or options for settlement beyond 2003. As of December 31, 2002, the estimated fair value of the aforementioned crude oil and NGL options and swaps held by us was approximately ($2.8) million.

*Value at Risk.* We measure market risk in our natural gas and liquid marketing portfolios using value-at-risk, or VaR. We define VaR as a measure of the maximum expected loss over a given horizon under normal market conditions. VaR does not explicitly indicate potential realized losses. VaR does, however, implicitly indicate a firm's potential realized loss if market conditions were to remain constant or if the portfolio is liquidated within the specified time period. Our calculations are derived from Financial Engineering Association's VaR Works using the variance/co-variance method. We assume a one-day holding period with a 95% confidence level. There is a 95% (19 out of 20 business days) chance that the portfolio loss will be less than a specified amount if the entire portfolio were liquidated the next day. We began using this model for VaR in the third quarter of 2002. As of December 31, 2002, our VaR position for natural gas and liquid marketing portfolios was $412,000. This figure includes the risk related to our entire marketing portfolio of natural gas and liquid financial instruments and the related underlying physical transactions. We also measure market risk by sensitivity valuations. As of December 31, 2002, an increase in natural gas prices of $1.00 would lead to an increase in the fair value of our marketing portfolio of $1.6 million and an increase in crude oil prices of $5.00 would lead to an increase in the fair value of our marketing portfolio of $611,000. To the extent that a transaction is not fully hedged or there is any hedge ineffectiveness, additional gains or losses associated with the transaction may be reported in future periods.

*Summary of Derivative Positions.* A summary of the change in our derivative position from December 31, 2001 to December 31, 2002 is as follows (dollars in thousands):

| | |
|---|---|
| Fair value of contracts outstanding at December 31, 2001 | $ 49,411 |
| Decrease in value due to change in price | (6,800) |
| Increase in value due to new contracts entered into during the period | 26,052 |
| Gains realized during the period from existing and new contracts | (68,600) |
| Changes in fair value attributable to changes in valuation techniques | - |
| Fair value of contracts outstanding at December 31, 2002 | $ 63 |

A summary of our outstanding derivative positions at December 31, 2002 is as follows (dollars in thousands):

| | Fair Value of Contracts at December 31, 2002 | | | | |
|---|---|---|---|---|---|
| Source of Fair Value | Total Fair Value | Maturing In 2003 | Maturing In 2004-2005 | Maturing In 2006-2007 | Maturing Thereafter |
| Exchange published prices | ($ 24,885) | ($ 25,138) | $ 253 | - | - |
| Other actively quoted prices (1) | 27,127 | 27,380 | (196) | ($ 57) | - |
| Other valuation methods (2) | (2,179) | (2,180) | 1 | - | - |
| Total fair value | $ 63 | $ 62 | $ 58 | ($ 57) | - |

(1) Other actively quoted prices are derived from broker quotations, trade publications, and industry indices.
(2) Other valuation methods are the Black-Scholes option-pricing model utilizing prices and volatility obtained from broker quotations, trade publications, and industry indices.

*Foreign Currency Derivative Market Risk.* As a normal part of our business, we enter into physical gas transactions which are payable in Canadian dollars. We enter into forward purchases and sales of Canadian dollars from time to time to fix the cost of our future Canadian dollar denominated natural gas purchase, sale, storage, and transportation obligations. This is done to protect marketing margins from adverse changes in the U.S. and Canadian dollar exchange rate between the time the commitment for the payment obligation is made and the actual payment date of such obligation. As of December 31, 2002, the net notional value of such contracts was approximately $14.4 million in Canadian dollars, which approximates fair market value.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

Western Gas Resources, Inc.'s Consolidated Financial Statements as of December 31, 2002 and 2001 and for each of the three years in the period ended December 31, 2002:

REPORT OF MANAGEMENT

The financial statements and other financial information included in this Annual Report on Form 10-K are the responsibility of Management. The financial statements have been prepared in conformity with generally accepted accounting principles appropriate in the circumstances and include amounts that are based on Management's informed judgments and estimates.

Management relies on the Company's system of internal accounting controls to provide reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with Management's authorization. The concept of reasonable assurance is based on the recognition that there are inherent limitations in all systems of internal accounting control and that the cost of such systems should not exceed the benefits to be derived. The internal accounting controls, including internal audit, in place during the periods presented are considered adequate to provide such assurance.

PricewaterhouseCoopers LLP, independent accountants, audits the Company's financial statements. Their report states that they have conducted their audit in accordance with generally accepted auditing standards. These standards include an evaluation of the system of internal accounting controls for the purpose of establishing the scope of audit testing necessary to allow them to render an independent professional opinion on the fairness of the Company's financial statements.

Oversight of Management's financial reporting and internal accounting control responsibilities is exercised by the board of directors, through an Audit Committee that consists solely of outside directors. The Audit Committee meets periodically with financial management, internal auditors and the independent accountants to review how each is carrying out its responsibilities and to discuss matters concerning auditing, internal accounting control and financial reporting. The independent accountants and the Company's internal audit department have free access to meet with the Audit Committee without Management present.

/S/ Peter A. Dea
Peter A. Dea
Chief Executive Officer and President

/S/ William J. Krysiak
William J. Krysiak
Executive Vice President - Chief Financial Officer (Principal Financial and Accounting Officer)

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and
Stockholders of Western Gas Resources, Inc.

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Western Gas Resources, Inc. and its subsidiaries at December 31, 2002 and 2001, and the results of their cash flows and their operations for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 4 to the financial statements, the Company changed its method of accounting for derivative instruments and hedging activities effective January 1, 2001.

PricewaterhouseCoopers LLP

Denver, Colorado
February 19, 2003

WESTERN GAS RESOURCES, INC.
CONSOLIDATED BALANCE SHEET
(000s, except share data)

| | December 31, 2002 | December 31, 2001 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 7,312 | $ 10,032 |
| Trade accounts receivable, net | 253,587 | 220,537 |
| Inventory | 43,482 | 50,773 |
| Assets held for sale | 3,250 | - |
| Assets from price risk management activities | 34,873 | 66,271 |
| Other | 27,744 | 18,350 |
| Total current assets | 370,248 | 365,963 |
| Property and equipment: | | |
| Gas gathering, processing, storage and transportation | 942,147 | 912,003 |
| Oil and gas properties and equipment (successful efforts method) | 252,747 | 193,656 |
| Construction in progress | 104,033 | 106,385 |
| | 1,298,927 | 1,212,044 |
| Less: Accumulated depreciation, depletion and amortization | (432,281) | (363,737) |
| Total property and equipment, net | 866,646 | 848,307 |
| Other assets: | | |
| Gas purchase contracts (net of accumulated amortization of $37,232 and $35,329, respectively) | 30,924 | 32,826 |
| Assets from price risk management activities | 406 | 2,934 |
| Other | 33,920 | 17,912 |
| Total other assets | 65,250 | 53,672 |
| Total assets | $ 1,302,144 | $ 1,267,942 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 242,987 | $ 260,208 |
| Accrued expenses | 51,509 | 23,123 |
| Liabilities from price risk management activities | 34,811 | 18,075 |
| Dividends payable | 3,464 | 3,767 |
| Total current liabilities | 332,771 | 305,173 |
| Long-term debt | 359,933 | 366,667 |
| Other long-term liabilities | 1,713 | 2,284 |
| Liabilities from price risk management activities | 406 | 1,720 |
| Deferred income taxes payable | 124,253 | 118,746 |
| Total liabilities | 819,076 | 794,590 |
| Commitments and contingent liabilities (Note 8) | - | - |
| Stockholders' equity: | | |
| Preferred Stock; 10,000,000 shares authorized: | | |
| $2.28 cumulative preferred stock, par value $.10; - and 591,136 shares issued, respectively | - | 59 |
| $2.625 cumulative convertible preferred stock, par value $.10; 2,760,000 issued ($138,000,000 aggregate liquidation preference) | 276 | 276 |
| Common stock, par value $.10; 100,000,000 shares authorized; 33,077,611 and 32,689,009 shares issued, respectively | 3,329 | 3,293 |
| Treasury stock, at cost; 25,016 common shares at 12/31/02; 25,016 common shares and 44,290 $2.28 cumulative preferred shares at 12/31/01, in treasury | (788) | (1,907) |
| Additional paid-in capital | 381,066 | 387,505 |
| Retained earnings | 102,292 | 66,128 |
| Accumulated other comprehensive income (loss) | (2,812) | 18,882 |
| Notes receivable from key employees secured by common stock | (295) | (884) |
| Total stockholders' equity | 483,068 | 473,352 |
| Total liabilities and stockholders' equity | $ 1,302,144 | $ 1,267,942 |

The accompanying notes are an integral part of the consolidated financial statements.

WESTERN GAS RESOURCES, INC.
CONSOLIDATED STATEMENT OF CASH FLOWS
(000s)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Reconciliation of net income to net cash provided by operating activities: | | | |
| Net income | $ 50,589 | $ 95,637 | $ 56,108 |
| Add income items that do not affect operating cash flows: | | | |
| Depreciation, depletion and amortization | 77,005 | 64,162 | 57,919 |
| Deferred income taxes | 19,614 | 42,815 | 32,712 |
| Distributions less than equity income, net | (2,906) | (29) | (1,137) |
| (Gain) loss on the sale of property and equipment | 948 | (10,748) | (9,406) |
| Non-cash change in fair value of derivatives | 13,788 | (19,906) | - |
| Compensation expense from re-priced stock options | 224 | 170 | 1,879 |
| Other non-cash items, net | 1,809 | 1,405 | 1,804 |
| Adjustments to working capital to arrive at net cash provided by operating activities: | | | |
| (Increase) decrease in trade accounts receivable | (35,216) | 313,215 | (350,644) |
| (Increase) decrease in product inventory | 7,164 | (5,951) | (9,594) |
| Decrease in parts inventory | - | 440 | 1,612 |
| Decrease (increase) in other current assets | (13,329) | (4,314) | 3,570 |
| Decrease (increase) in other assets and liabilities, net | 348 | (1,188) | 424 |
| Increase (decrease) in accounts payable | (16,394) | (321,355) | 348,892 |
| (Decrease) increase in accrued expenses | 27,492 | (1,086) | (17,877) |
| Total adjustments | (29,935) | (20,239) | (23,617) |
| Net cash provided by operating activities | 131,136 | 153,267 | 116,262 |
| Cash flows from investing activities: | | | |
| Purchases of property and equipment, including acquisitions | (125,600) | (163,977) | (108,536) |
| Proceeds from the disposition of property and equipment | 34,865 | 38,094 | 26,484 |
| Contributions to equity investees | (15,037) | (5,774) | - |
| Distributions from equity investees | - | - | 13 |
| Net cash used in investing activities | (105,772) | (131,657) | (82,039) |
| Cash flows from financing activities: | | | |
| Net proceeds from exercise of common stock options | 6,489 | 5,191 | 2,680 |
| Payments for the re-purchase of preferred stock | - | (129) | (990) |
| Payments for the redemption of preferred stock | (12,607) | (20,591) | - |
| Payments on long-term debt | (8,333) | (33,333) | (27,000) |
| Borrowings under revolving credit facility | 994,545 | 569,630 | 1,399,736 |
| Payments on revolving credit facility | (992,945) | (528,330) | (1,392,286) |
| Debt issue costs paid | (126) | (97) | (621) |
| Dividends paid | (15,107) | (16,846) | (16,877) |
| Net cash used in financing activities | (28,084) | (24,505) | (35,358) |
| Net decrease in cash and cash equivalents | (2,720) | (2,895) | (1,135) |
| Cash and cash equivalents at beginning of year | 10,032 | 12,927 | 14,062 |
| Cash and cash equivalents at end of year | $ 7,312 | $ 10,032 | $ 12,927 |

The accompanying notes are an integral part of the consolidated financial statements.

WESTERN GAS RESOURCES, INC.
CONSOLIDATED STATEMENT OF OPERATIONS
(000s, except share and per share amounts)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2002 | 2001 | 2000 |
| Revenues: | | | |
| Sale of gas | $ 2,123,468 | $ 2,849,097 | $ 2,628,052 |
| Sale of natural gas liquids | 309,697 | 424,082 | 590,932 |
| Gathering, processing and transportation revenue | 65,601 | 55,398 | 53,156 |
| Non-cash change in fair value of derivatives | (13,788) | 19,906 | - |
| Other | 4,720 | 4,679 | 7,951 |
| Total revenues | 2,489,698 | 3,353,162 | 3,280,091 |
| Costs and expenses: | | | |
| Product purchases | 2,157,179 | 2,986,950 | 2,985,501 |
| Plant and transportation operating expense | 81,530 | 75,533 | 69,892 |
| Oil and gas exploration and production costs | 34,007 | 27,527 | 19,521 |
| Depreciation, depletion and amortization | 77,005 | 64,162 | 57,919 |
| Selling and administrative expense | 35,828 | 34,272 | 33,717 |
| (Gain) loss on sale of assets | 948 | (10,748) | (9,406) |
| Earnings from equity investments | (4,453) | (1,790) | (1,897) |
| Interest expense | 26,951 | 25,130 | 33,460 |
| Total costs and expenses | 2,408,995 | 3,201,036 | 3,188,707 |
| Income before income taxes | 80,703 | 152,126 | 91,384 |
| Provision for income taxes: | | | |
| Current | 10,500 | 13,674 | 850 |
| Deferred | 19,614 | 42,815 | 32,712 |
| Total provision for income taxes | 30,114 | 56,489 | 33,562 |
| Income before extraordinary item | 50,589 | 95,637 | 57,822 |
| Extraordinary charge for early extinguishment of debt, net of tax benefit of $997,000 | - | - | (1,714) |
| Net income | $ 50,589 | $ 95,637 | $ 56,108 |
| Preferred stock requirements | (9,198) | (11,167) | (10,416) |
| Net income attributable to common stock | $ 41,391 | $ 84,470 | $ 45,692 |
| Net income per share of common stock before extraordinary item | $ 1.26 | $ 2.59 | $ 1.47 |
| Extraordinary item per share of common stock, net of tax | $ - | $ - | $ (.05) |
| Net income per share of common stock | $ 1.26 | $ 2.59 | $ 1.42 |
| Weighted average shares of common stock outstanding | 32,952,543 | 32,579,813 | 32,240,755 |
| Net income per share of common stock - assuming dilution | $ 1.23 | $ 2.48 | $ 1.39 |
| Weighted average shares of common stock outstanding - assuming dilution | 33,607,560 | 37,022,369 | 32,834,641 |

The accompanying notes are an integral part of the consolidated financial statements.

WESTERN GAS RESOURCES, INC.
CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY
(000s, except share amounts)

| | Shares of $2.28 Cumulative Preferred Stock | Shares of $2.625 Cumulative Convertible Preferred Stock | Shares of Common Stock | Shares of Common Stock in Treasury | Shares of $2.28 Cumulative Preferred Stock in Treasury | $2.28 Cumulative Preferred Stock | $2.625 Cumulative Convertible Preferred Stock | Common Stock | Treasury Stock | Additional Paid-In Capital | Retained (Deficit) Earnings | Accumulated Other Comprehensive Income (Loss) Net of Tax | Notes Receivable from Key Employees | Total Stock-holders' Equity |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Balance at December 31, 1999 | 1,400,000 | 2,760,000 | 32,161,731 | 25,016 | - | 140 | 276 | 3,220 | (788) | 397,522 | (51,064) | 1,321 | (884) | 349,743 |
| Comprehensive income: | | | | | | | | | | | | | | |
| Net income, 2000 | - | - | - | - | - | - | - | - | - | - | 56,108 | - | - | 56,108 |
| Translation adjustments | - | - | - | - | - | - | - | - | - | - | - | 857 | - | 857 |
| Stock options exercised | - | - | 199,400 | - | - | - | - | 45 | - | 2,635 | - | - | - | 2,680 |
| Tax benefit related to stock options | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Loans forgiven | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Dividends declared on common stock | - | - | - | - | - | - | - | - | - | - | (6,448) | - | - | (6,448) |
| Dividends declared on $2.28 cumulative preferred stock | - | - | - | - | - | - | - | - | - | - | (3,171) | - | - | (3,171) |
| Dividends declared on $2.625 cumulative convertible preferred stock | - | - | - | - | - | - | - | - | - | - | (7,245) | - | - | (7,245) |
| Repurchase of $2.28 cumulative preferred stock | - | - | - | - | 39,190 | - | - | - | (990) | - | - | - | - | (990) |
| Balance at December 31, 2000 | 1,400,000 | 2,760,000 | 32,361,131 | 25,016 | 39,190 | $ 140 | $ 276 | $ 3,265 | $ (1,778) | $400,157 | $ (11,820) | $ 2,178 | $ (884) | $391,534 |
| Comprehensive income: | | | | | | | | | | | | | | |
| Net income, 2001 | - | - | - | - | - | - | - | - | - | - | 95,637 | - | - | 95,637 |
| Translation adjustments | - | - | - | - | - | - | - | - | - | - | - | (440) | - | (440) |
| Cumulative effect of change in accounting principal | - | - | - | - | - | - | - | - | - | - | - | (22,527) | - | (22,527) |
| Reclassification adjustment for settled contracts | - | - | - | - | - | - | - | - | - | - | - | 21,988 | - | 21,988 |
| Changes in fair value of outstanding hedge positions | - | - | - | - | - | - | - | - | - | - | - | 5,772 | - | 5,772 |
| Fair value of new hedge positions | - | - | - | - | - | - | - | - | - | - | - | 11,911 | - | 11,911 |
| Ending accumulated derivative gain | - | - | - | - | - | - | - | - | - | - | - | 17,144 | - | 17,144 |
| Total comprehensive income, net of tax | | | | | | | | | | | | | | 112,341 |
| Stock options exercised | - | - | 327,878 | - | - | - | - | 28 | - | 5,163 | - | - | - | 5,191 |
| Effect of re-priced options | - | - | - | - | - | - | - | - | - | (170) | - | - | - | (170) |
| Tax benefit related to stock options | - | - | - | - | - | - | - | - | - | 1,584 | - | - | - | 1,584 |
| Dividends declared on common stock | - | - | - | - | - | - | - | - | - | - | (6,524) | - | - | (6,524) |
| Dividends declared on $2.28 cumulative preferred stock | - | - | - | - | - | - | - | - | - | - | (2,640) | - | - | (2,640) |
| Dividends declared on $2.625 cumulative convertible preferred stock | - | - | - | - | - | - | - | - | - | - | (7,244) | - | - | (7,244) |
| Redemption of $2.28 cumulative preferred stock | (808,864) | - | - | - | - | (81) | - | - | - | (19,229) | (1,281) | - | - | (20,591) |
| Repurchase of $2.28 cumulative preferred stock | - | - | - | - | 5,100 | - | - | - | (129) | - | - | - | - | (129) |
| Balance at December 31, 2001 | 591,136 | 2,760,000 | 32,689,009 | 25,016 | 44,290 | $ 59 | $ 276 | $ 3,293 | $ (1,907) | $387,505 | $ 66,128 | $ 18,882 | $ (884) | $473,352 |
| Comprehensive income: | | | | | | | | | | | | | | |
| Net income, 2002 | - | - | - | - | - | - | - | - | - | - | 50,589 | - | - | 50,589 |
| Other comprehensive income from equity investees | - | - | - | - | - | - | - | - | - | - | - | 556 | - | 556 |

| | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Translation adjustments | - | - | - | - | - | - | - | - | - | - | - | 283 | - | 283 |
| Reclassification adjustment for settled contracts | - | - | - | - | - | - | - | - | - | - | - | (17,142) | - | (17,142) |
| Changes in fair value of outstanding hedge positions | - | - | - | - | - | - | - | - | - | - | - | (119) | - | (119) |
| Fair value of new hedge positions | - | - | - | - | - | - | - | - | - | - | - | (5,272) | - | (5,272) |
| Change in accumulated derivative comprehensive income | - | - | - | - | - | - | - | - | - | - | - | (22,533) | - | (22,533) |
| Total comprehensive income, net of tax | - | - | - | - | - | - | - | - | - | - | - | - | - | 28,895 |
| Stock options exercised | - | - | 388,602 | - | - | - | - | 36 | - | 5,975 | - | - | - | 6,011 |
| Effect of re-priced options | - | - | - | - | - | - | - | - | - | 478 | - | - | - | 478 |
| Officer loans forgiven | - | - | - | - | - | - | - | - | - | - | - | - | 589 | 589 |
| Tax benefit related to stock options | - | - | - | - | - | - | - | - | - | 1,154 | - | - | - | 1,154 |
| Dividends declared on common stock | - | - | - | - | - | - | - | - | - | - | (6,603) | - | - | (6,603) |
| Dividends declared on $2.28 cumulative preferred stock | - | - | - | - | - | - | - | - | - | - | (957) | - | - | (957) |
| Dividends declared on $2.625 cumulative convertible preferred stock | - | - | - | - | - | - | - | - | - | - | (7,244) | - | - | (7,244) |
| Redemption of $2.28 cumulative preferred stock | (591,136) | - | - | - | (44,290) | (59) | - | - | 1,119 | (14,046) | 379 | - | - | (12,607) |
| Balance at December 31, 2002 | - | 2,760,000 | 33,077,611 | 25,016 | - | $ - | $ 276 | $ 3,329 | $ (788) | $381,066 | $ 102,292 | $ (2,812) | $ (295) | $483,068 |

The accompanying notes are an integral part of the consolidated financial statements.

## NOTE 1 - NATURE OF ORGANIZATION

Western Gas Resources, Inc. (the "Company") explores for, develops and produces, gathers, processes and treats, transports and markets natural gas and natural gas liquids ("NGLs"). In its upstream operations, the Company explores for, develops and produces natural gas reserves primarily in the Rocky Mountain region. In its midstream operations the Company designs, constructs, owns and operates natural gas gathering, processing and treating facilities and owns and operates regulated transportation facilities and offers marketing services in order to provide its customers with a broad range of services from the wellhead to the sales delivery point. The Company's midstream operations are conducted in major gas-producing basins in the Rocky Mountain, Mid-Continent and Southwestern regions of the United States.

The Company has completed three public offerings of Common Stock. In December 1989, the Company issued 3,527,500 shares of Common Stock at a public offering price of $11.50. In November 1991, the Company issued 4,115,000 shares of Common Stock at a public offering price of $18.375 per share. In November 1996, the Company issued 6,325,000 shares of Common Stock at a public offering price of $16.25 per share.

The Company has also completed two public offerings of preferred stock. In November 1992, the Company issued 1,400,000 shares of $2.28 Cumulative Preferred Stock with a liquidation preference of $25 per share, at a public offering price of $25 per share, redeemable at the Company's option on or after November 15, 1997. In 2000, the Company re-purchased 39,190 of the $2.28 Cumulative Preferred Stock for a total consideration of approximately $1.0 million. In 2001, the Company purchased in open market transactions an additional 5,100 shares of this preferred stock for a total cost, including broker commissions, of approximately $129,000, or an average of $25.29 per share of preferred stock. In December 2001, the Company redeemed 808,864 shares of this preferred stock at the liquidation preference for total proceeds of $20.6 million including accrued and unpaid dividends. In December 2002, the Company redeemed the remaining 546,846 shares of this preferred stock at the liquidation preference for total proceeds of $14.0 million including accrued and unpaid dividends. This redemption was funded with amounts available under the Revolving Credit Facility.

In February 1994, the Company issued 2,760,000 shares of $2.625 Cumulative Convertible Preferred Stock with a liquidation preference of $50 per share, at a public offering price of $50 per share, redeemable at the Company's option on or after February 16, 1997 and convertible at the option of the holder into Common Stock at a per share conversion price of $39.75.

In 2001, the Company adopted a Stockholder Rights Plan under which rights were distributed as a dividend at the rate of one right for each share of its common stock held by stockholders of record as of the close of business on April 9, 2001. Each right initially will entitle stockholders to buy one unit consisting of $1/100^{th}$ of a share of a new series of preferred stock for $180 per unit. The right generally will be exercisable only if a person or group acquires beneficial ownership of 15% or more of the Company's then outstanding common stock or commences a tender or exchange offer upon consummation of which a person or group would beneficially own 15% or more of its then outstanding common stock. The rights will expire on March 22, 2011.

***Significant Projects and Asset Divestitures***

***Toca Processing Facility.*** In June 2002, the Company entered into an agreement for the sale of its Toca processing facility in Louisiana. This sale closed in September 2002. The sale price was $32.2 million, subject to accounting adjustments, and resulted in a pre-tax loss of approximately $448,000. During the year ended December 31, 2002, this facility generated net after-tax earnings of approximately $683,000, or $.02 per share of common stock, respectively. The Company believes the results from this facility are immaterial for separate presentation as a discontinued operation. Approximately $15.0 million of the proceeds received from this asset sale were initially used to reduce amounts outstanding on the Company's Revolving Credit Facility. At December 31, 2002, the remaining amount of $17.2 million was on deposit with a trustee in anticipation of the completion of a like-kind exchange transaction and was reflected on the Consolidated Balance Sheet under the caption Other current assets. These funds, along with additional amounts drawn on our Revolving Credit Facility, were used in a January 2003 acquisition of several gathering systems.

***Powder River Basin Coal Bed Methane.*** The Company continues to develop its Powder River Basin coal bed methane reserves and expand the associated gathering system in northeast Wyoming. During the years ended December 31, 2002, 2001 and 2000, the Company expended approximately $71.0 million, $82.1 million and $59.1 million, respectively, on this project.

In December 1998, the Company joined with other industry participants to form the Fort Union Gas Gathering, L.L.C. ('Fort Union"), to construct a gathering pipeline and treater in the Powder River Basin in northeast Wyoming. The Company owns an approximate 13% interest in Fort Union and is the construction manager and field operator.

*Green River Basin.* The Company's assets in southwest Wyoming are comprised of the Granger and Lincoln Road facilities (collectively the "Granger Complex"), its 50% equity interest in Rendezvous Gas Services, L.L.C. ("Rendezvous"), the Red Desert facility and production from the Jonah Field and Pinedale Anticline areas. During the years ended December 31, 2002, 2001 and 2000, the Company expended approximately $36.2 million, $27.2 million and $8.0 million, respectively, in this area.

In 2001, the Company sold a 50% interest in a segment of the gathering system behind its Granger facility, along with associated field compression to an unrelated third party for $5.2 million. Together, the Company and the third party contributed their respective interests in this system along with additional field compression and gathering dedications for gas produced along the Pinedale Anticline to a newly formed limited liability corporation named Rendezvous Gas Services, L.L.C. Each company owns a 50% interest in Rendezvous, and the Company serves as field operator of its systems. Rendezvous was formed to gather gas along the Pinedale Anticline for blending or processing at either the Company's Granger Complex or at Questar's Blacks Fork processing facility.

*Pinnacle Gas Treating, Inc.* In December 2000, the Company signed an agreement with Anadarko Petroleum Corporation for the sale of the stock of the Company's wholly owned subsidiary Pinnacle Gas Treating, Inc. for approximately $38.0 million. The sale closed in January 2001 and resulted in an approximate pre-tax gain for financial reporting purposes of $12.1 million in the first quarter of 2001.

*Arkoma.* In August 2000, the Company sold its Arkoma Gathering System in Oklahoma for gross proceeds of $10.5 million. This sale resulted in an approximate pre-tax gain of $3.9 million.

*Western Gas Resources – California, Inc.* In January 2000, the Company sold all of the outstanding stock of its wholly owned subsidiary Western Gas Resources – California, Inc. ("WGR-California") for $14.9 million. The only asset of this subsidiary was a 162 mile pipeline in the Sacramento Basin of California. WGR-California acquired the pipeline through the exercise of a purchase option in a transaction that closed immediately prior to the sale by the Company of WGR-California. The Company recognized a pre-tax gain on the sale of WGR-California of approximately $5.4 million in the first quarter of 2000.

## NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies followed by the Company and its wholly owned subsidiaries are presented here to assist the reader in evaluating the financial information contained herein. The Company's accounting policies are in accordance with generally accepted accounting principles.

*Principles of Consolidation.* The consolidated financial statements include the accounts of the Company and the Company's wholly owned subsidiaries. All material inter-company transactions have been eliminated in consolidation. The Company's interest in certain non-controlled investments is accounted for by the equity method.

*Inventories.* The cost of gas and NGL inventories are determined by the weighted average cost method on a location-by-location basis. Residue and NGL inventory covered by derivative contracts is accounted for on a specific identification basis. Product inventory includes $42.1 million and $48.3 million of gas and $1.4 million and $2.5 million of NGLs at December 31, 2002 and 2001, respectively.

*Property and Equipment.* Property and equipment is recorded at the lower of cost, including capitalized interest, or estimated realizable value. Interest incurred during the construction period of new projects is capitalized and amortized over the life of the associated assets. Repair and maintenance of property and equipment is expensed as incurred.

Depreciation is provided using the straight-line method based on the estimated useful life of each facility, which ranges from three to 35 years. Useful lives are determined based on the shorter of the life of the equipment or the reserves serviced by the equipment. The cost of acquired gas purchase contracts is amortized using the straight-line method or units of production.

*Oil and Gas Properties and Equipment.* The Company follows the successful efforts method of accounting for oil and gas exploration and production activities. Acquisition costs, development costs and successful exploration costs are capitalized. Exploratory dry hole costs, lease rentals and geological and geophysical costs are charged to expense as incurred. Upon surrender of undeveloped properties, the original cost is charged against income. Producing properties and related equipment are depleted and depreciated by the units-of-production method based on estimated proved reserves.

*Income Taxes.* Deferred income taxes reflect the impact of temporary differences between amounts of assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. These temporary differences are determined and accounted for in accordance with SFAS No. 109, "Accounting for Income Taxes."

*Foreign Currency Adjustments.* The Company has a subsidiary in Canada. The assets and liabilities associated with this subsidiary are translated into U.S. dollars at the exchange rate as of the balance sheet date and revenues and expenses at the weighted-average of exchange rates in effect during each reporting period. The translation gains (losses) for the years ended December 31, 2002, 2001 and 2000 were $283,000, $(440,000) and $857,000, respectively, net of tax.

*Revenue Recognition.* In the Gathering, Processing and Treating segment, the Company recognizes revenue for its services at the time the service is performed. The Company records revenue from its gas and NGL marketing activities, including sales of the Company's equity production, upon transfer of title to the product. These revenues are recorded on a gross sales versus sales net of purchases basis as the Company obtains title to all the gas and NGLs that it buys including third-party purchases, and bears the risk of loss and credit exposure on these transactions. For its marketing activities the Company utilizes mark-to-market accounting. Under mark-to-market accounting, the expected margin to be realized over the term of the transaction is recorded in the month of origination. To the extent that a transaction is not fully hedged or there is any hedge ineffectiveness, additional gains or losses associated with the transaction may be reported in future periods. In the Transportation segment, the Company realizes revenue on a monthly basis from firm capacity contracts under which the shipper pays for transport capacity whether or not the capacity is used and from interruptible contracts where a fee is charged based upon volumes received into the pipeline. See additional discussion in Note 9 – Business Segments and Related Information.

*Accounting for Derivative Instruments and Hedging Activities.* Prior to January 1, 2001 and the implementation of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), gains and losses on hedges of product inventory were included in the carrying amount of the inventory and were ultimately recognized in gas and NGL sales when the related inventory was sold. Gains and losses related to qualifying hedges, as defined by SFAS No. 80, "Accounting for Futures Contracts," of firm commitments or anticipated transactions (including hedges of equity production) were recognized in gas and NGL sales when the hedged physical transaction occurred. For purposes of the Consolidated Statement of Cash Flows, all hedging gains and losses were classified in net cash provided by operating activities. To the extent the Company engaged in speculative transactions, they were marked to market at the end of each accounting period and any gain or loss was recognized in income for that period. Such amounts were negligible in 2000.

In June 1998, the Financial Accounting Standards Board, (the "FASB"), issued SFAS No. 133 effective for fiscal years beginning after June 15, 2000. Under SFAS No. 133, which was subsequently amended by SFAS No.138, the Company is required to recognize the change in the market value of all derivatives, including storage contracts and firm transportation to the extent utilized, as either assets or liabilities in the statement of financial position and measure those instruments at fair value. Changes in the fair value of derivatives are recorded each period in current earnings or other comprehensive income depending upon the nature of the underlying transaction. Upon adoption of SFAS No. 133 and mark-to-market accounting on January 1, 2001, the impact was a decrease in a component of stockholders' equity through Accumulated other comprehensive income of $22.5 million, an increase to Current assets of $52.6 million, an increase to Current liabilities of $86.9 million, an increase in Other long-term liabilities of $1.1 million and a decrease in Deferred income taxes payable of $12.9 million.

Of the $22.5 million decrease to Accumulated other comprehensive income resulting from the January 1, 2001 adoption of SFAS No. 133, $22.0 million was reversed during the year ended December 31, 2001 with gains and losses from the underlying transactions recognized through operating income. The remaining $500,000 of this transition entry was recognized through operating income during 2002. The non-cash impact to the Company's results of operations in the year ended December 31, 2001 resulting from the adoption of mark-to-market accounting for its marketing activities resulted in additional pre-tax income of $19.9 million.

*Comprehensive Income.* Accumulated other comprehensive income (loss) is reported as a separate component of stockholders' equity. Accumulated other comprehensive income (loss) includes cumulative translation adjustments for foreign currency transactions and the change in fair market value of cash flow hedges. The Company's accumulated derivative losses at December 31, 2002 total $5.4 million and will be reclassified into earnings during 2003. These items are separately reported on the Consolidated Statement of Changes in Stockholders' Equity.

*Impairment of Long-Lived Assets.* SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of" ("SFAS No. 121") required that long-lived assets be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Effective for the Company's year ended December 31, 2002, SFAS No. 121 was superseded by SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" ("SFAS No. 144"). SFAS No. 144 also requires that long-lived assets be reviewed whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company reviews its assets at the plant facility, related group of plant facilities or the oil and gas producing property levels. In order to determine whether an impairment exists, the Company compares its net book value of the asset to the estimated fair market value or the undiscounted expected future net cash flows, determined by applying future prices estimated by management over the shorter of the lives of the facilities or the reserves supporting the facilities. If an impairment exists, write-downs of assets are based upon expected future net cash flows discounted using an interest rate commensurate with the risk associated with the underlying asset. There were no write-downs in 2002, 2001or 2000.

*Earnings Per Share of Common Stock.* The Company follows SFAS No. 128, "Earnings per Share" ("SFAS No. 128"), which requires that earnings per share and earnings per share - assuming dilution be calculated and presented on the Consolidated Statement of Operations. In accordance with SFAS No. 128, earnings per share of common stock are computed by dividing income attributable to common stock by the weighted average shares of common stock outstanding. In addition, earnings per share of common stock - assuming dilution is computed by dividing income attributable to common stock by the weighted average shares of common stock outstanding as adjusted for potential common shares. Income attributable to common stock is income less preferred stock dividends. The Company declared preferred stock dividends of $8.2 million, $11.2 million and $10.4 million for each of the years ended December 31, 2002, 2001 and 2000, respectively. SFAS No. 128 dictates that the computation of earnings per share shall not assume conversion, exercise or contingent issuance of securities that would have an anti-dilutive effect on earnings per share. Common stock options, which are potential common shares, increased the number of common shares used in the computation by 655,017 and 593,886 in 2002 and 2000, respectively. The computations for the years ended December 31, 2002 and 2000 were not adjusted to reflect the conversion of the Company's $2.625 Cumulative Convertible Preferred Stock outstanding. In those years, the shares are antidilutive as the incremental shares result in an increase in earnings per share after giving effect to the preferred dividend requirements. The computation for the year ended December 31, 2001 reflects the conversion of the Company's $2.625 Cumulative Convertible Preferred Stock and dilutive stock options totaling 4,442,556.

*Concentration of Credit Risk.* Financial instruments that potentially subject the Company to concentrations of credit risk consist principally of trade accounts receivable and over-the-counter ("OTC") swaps and options. The risk is limited due to the large number of entities comprising the Company's customer base and their dispersion across industries and geographic locations.

The Company continually monitors and reviews the credit exposure to its marketing counter parties. This review has resulted in a reduction in sales volumes with various counter parties in order to maintain acceptable credit exposures. During 2002, 2001 and 2000, the Company reserved approximately $1.6 million, $2.7 million and $1.6 million for doubtful accounts through a charge to Selling and administrative expense. The Company records a reserve for doubtful accounts on a specific identification basis and the balance in the reserve for doubtful accounts was $3.9 million and $2.3 million, respectively at December 31, 2002 and 2001. During the years ended December 31, 2002, 2001and 2000, the Company sold gas to a variety of customers including end-users, pipelines, energy merchants, LDCs and others. Two customers accounted for approximately 10% of the Company's consolidated revenues from the sale of gas, or 9% of total consolidated revenue, for the year ended December 31, 2002. One of these customers is an energy merchant and the other customer is an electric utility. One customer accounted for approximately 5% of the Company's consolidated revenues from the sale of gas, or 4% of total consolidated revenue, for the year ended December 31, 2001. This customer is a wholly owned subsidiary of a major integrated oil company.

During the years ended December 31, 2002, 2001 and 2000, the Company sold NGLs to a variety of customers including end-users, fractionators, chemical companies, energy merchants and other customers. In 2002, three customers accounted for approximately 38% of the Company's consolidated revenues from the sale of NGLs, or 5% of total consolidated revenue. One of these customers is a large integrated energy company, another is a large petrochemical company and the third is an energy merchant. In 2001, three customers accounted for approximately 37% of the Company's consolidated revenues from the sale of NGLs, or 5% of total consolidated revenue. These customers were all large integrated energy companies.

On December 2, 2001, Enron Corp. and many of its affiliates and subsidiaries filed a petition for bankruptcy protection under Chapter 11 of the Bankruptcy code in the Southern District of New York. At the time of Enron's filing, the Company's exposure to them totaled approximately $2.7 million. This amount includes the net exposure from physical gas transactions of $100,000, which is comprised of physical gas sales of $8.4 million and physical gas purchases of $8.3 million. The Company has in place a netting agreement with Enron for the purchase and sale of physical gas. Although bankruptcy courts have upheld similar netting agreements in the past, the Company can provide no assurance that its agreement will not be challenged or the outcome of any challenge. The remaining $2.6 million of its net exposure is under a Master Swap Agreement related to derivative transactions, including approximately $180,000 which was related to discontinued hedges and will be relieved from Accumulated other comprehensive earnings as the hedged transactions occur. As a result, the Company incurred an additional charge to income of $2.7 million in 2001.

*Cash and Cash Equivalents.* Cash and cash equivalents includes all cash balances and highly liquid investments with an original maturity of three months or less.

*Supplementary Cash Flow Information.* Interest paid was $28.1 million, $30.2 million and $36.5 million, respectively, for the years ended December 31, 2002, 2001 and 2000. Capitalized interest associated with construction of new projects was $1.7 million, $4.7 million and $3.4 million, respectively, for the years ended December 31, 2002, 2001 and 2000. Income taxes paid were $1.5 million, $18.7 million and $400,000, respectively, for the years ended December 31, 2002, 2001 and 2000.

*Stock Compensation.* As permitted under SFAS No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"), the Company has elected to continue to measure compensation costs for stock-based employee compensation plans as prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." The Company has complied with the pro forma disclosure requirements of SFAS No. 123 as required under the pronouncement. The Company realizes an income tax benefit from the exercise of non-qualified stock options related to the difference between the market price at the date of exercise and the option price. This difference is credited to additional paid-in capital.

In March 2000, the FASB issued Interpretation No. 44, an interpretation of APB Opinion No. 25, "Accounting for Certain Transactions Involving Stock Compensation," regarding the accounting treatment of re-priced stock options. This interpretation became effective July 1, 2000. Under this interpretation, the Company is required to record compensation expense (if not previously accrued) equal to the number of unexercised re-priced options multiplied by the amount by which its stock price at the end of any quarter exceeds $21 per share. The Company had options covering 59,500, 118,028 and 148,133 common shares outstanding at December 31, 2002, 2001 and 2000, respectively, which were treated as re-priced options. Based on the Company's stock price at December 31, 2002, 2001and 2000 of $36.85, $32.32 and $33.69 per share, respectively; expense of $224,000, income of $170,000, and expense of $1.9 million was recorded in the years ended December 31, 2002, 2001, and 2000.

SFAS No. 123 encourages companies to record compensation expense for stock-based compensation plans at fair value. As permitted under SFAS No. 123, the Company has elected to continue to measure compensation costs for such plans as prescribed by APB No. 25. SFAS No. 123 requires pro forma disclosures for each year that a statement of operations is presented. Such information was only calculated for the options granted under the 1993, 1997, and 1999 Stock Option Plans, the 1999 Non-employee Directors' Stock Option Plan, the Chief Executive Officer's Plan, the 2002 Stock Option Plan and the 2002 Directors' Plan, as there were no grants under any other plans. There were no grants under the 1997 Plan during the years ended December 31, 2002 and 2001. The weighted average fair value of options granted under the 1999 Plan was $17.36, $19.26 and $21.20 for the years ended December 31, 2002, 2001 and 2000, respectively. The weighted average fair value of options granted under the Chief Executive Officer's Plan was $21.13 for the year ended December 31, 2001. The weighted average fair value of options granted under the 2002 Directors' Plan and the 2002 Plan were $22.50 and $17.44, respectively, for the year ended December 31, 2002. The weighted average fair value of options granted was estimated using the Black-Scholes option-pricing model with the following assumptions:

| | 1999 Plan | | | 2002 Plan | 2002 Directors' Plan | Chief Executive Officer's Plan |
|---|---|---|---|---|---|---|
| | 2002 | 2001 | 2000 | 2002 | 2002 | 2001 |
| Risk-free interest rate | 3.40% | 5.16% | 5.95% | 3.41% | 4.93% | 5.16% |
| Expected life (in years) | 5 | 5 | 5 | 5 | 5 | 5 |
| Expected volatility | 55% | 56% | 54% | 55% | 56% | 56% |
| Expected dividends (quarterly) | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 | $0.05 |

Had compensation expense for the Company's 2002, 2001 and 2000 grants for stock-based compensation plans been determined consistent with the fair value method under SFAS No. 123, the Company's net income, income attributable to common stock, earnings per share of common stock and earnings per share of common stock - assuming dilution would approximate the pro forma amounts below (000s, except per share amounts):

| | 2002 | | 2001 | | 2000 | |
|---|---|---|---|---|---|---|
| | As Reported | Pro forma | As Reported | Pro forma | As Reported | Pro forma |
| Net income | $ 50,589 | $ 47,978 | $ 95,637 | $ 93,120 | $ 56,108 | $ 54,374 |
| Net income attributable to common stock | 41,391 | 38,780 | 84,470 | 81,954 | 45,692 | 43,958 |
| Earnings per share of common stock | 1.26 | 1.18 | 2.59 | 2.52 | 1.42 | 1.36 |
| Earnings per share of common stock - assuming dilution | 1.23 | 1.15 | 2.48 | 2.41 | 1.39 | 1.34 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Stock-based employee compensation cost, net of related tax effects, included in net income .................... | 375 | - | (68) | - | 1,228 | - |
| Stock-based employee compensation cost, net of related tax effects, includable in net income if the fair value based method had been applied ........ | $ - | $ 2,987 | $ - | $ 2,448 | $ - | $ 2,962 |

The fair market value of the options at grant date is amortized over the appropriate vesting period for purposes of calculating compensation expense.

*Use of Estimates and Significant Risks.* The preparation of consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported for assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the amounts reported for revenues and expenses during the reporting period. Therefore, the reported amounts of our assets and liabilities, revenues and expenses and associated disclosures with respect to contingent assets and obligations are necessarily affected by these estimates. These estimates are evaluated on an ongoing basis, utilizing historical experience, consultation with experts and other methods considered reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the estimates used. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

The Company is subject to a number of risks inherent in the industry in which it operates, including price volatility, counter party credit risk, the success of its drilling programs and other gas supply. The Company's financial condition and results of operations will depend significantly upon the prices received for gas and NGLs. These prices are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond the control of the Company. In addition, the Company must continually connect new wells to its gathering systems in order to maintain or increase throughput levels to offset natural declines in dedicated volumes. The number of new wells drilled will depend upon, among other factors, prices for gas and oil, the drilling budgets of third-party producers, the energy policy of the federal government and the availability of foreign oil and gas, none of which are within the Company's control.

*Recently Issued Accounting Pronouncements.* In June 2001, the Financial Accounting Standards Board, (the "FASB"), issued SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 142 is effective for fiscal years beginning after December 15, 2001. SFAS No. 142 changes the method in which goodwill and other intangible assets are recorded and amortized. SFAS No. 142 did not have an immediate impact on the Company as it does not have any goodwill recorded in its financial statements.

In June 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. SFAS No. 143 establishes accounting standards for recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. The Company is in the process of determining its asset retirement costs in accordance with SFAS No. 143 and will adopt it on January 1, 2003. The Company expects to record a $11.5 million increase to Property and Equipment, a $4.4 million increase to Accumulated depreciation, depletion and amortization, a $17.8 million increase to Other long-term liabilities and a $10.7 million pre-tax loss from the Cumulative effect of a change in accounting principle in the first quarter of 2003.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FAS Statements No. 4, 44 and 64, Amendment of FAS Statement No. 13, and Technical Corrections," which is generally effective for fiscal years beginning after May 15, 2002. Through the rescission of SFAS Statements 4 and 64, SFAS No. 145 eliminates the requirement that gains and losses from extinguishment of debt be aggregated and, if material, be classified as an extraordinary item net of any income tax effect. SFAS No. 145 made several other technical corrections to existing pronouncements that may change accounting practice. The Company has adopted SFAS No. 145 for its fiscal year beginning January 1, 2003.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 is effective for exit or disposal activities that are initiated after December 31, 2002. This statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force, or EITF, Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." The Company does not believe that SFAS No. 146 will have a material impact on its earnings or financial position.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation-Transition and Disclosure, an amendment of SFAS No. 123." SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for fiscal years ending after December 31, 2002 and for interim periods beginning after December 15, 2002. The Company does not believe that SFAS No. 148 will have a material impact on its earnings or financial position as the Company continues to measure compensation costs for stock-based employee compensation plans as prescribed by Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." The Company will comply with requirements of SFAS No. 148 for interim periods beginning with the first quarter of 2003.

At an October 25, 2002 special meeting of the EITF, a consensus was reached to rescind EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." This impact of this decision is to preclude mark-to-market accounting for all energy trading contracts not within the scope of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The EITF also reached a consensus that gains and losses on derivative instruments within the scope of SFAS No. 133 should be shown net in the income statement if the derivative instruments are held for trading purposes. The consensus regarding the rescission of Issue 98-10 is applicable for fiscal periods beginning after December 15, 2002. Energy trading contracts not within the scope of SFAS No. 133 purchased after October 25, 2002, but prior to the implementation of the consensus are not permitted to apply mark-to-market accounting. EITF 02-03 was subsequently amended in January 2003 to further define energy trading contracts. Upon entering into a physical or derivative transaction, the Company is now required to designate its intention to either hold the contract to maturity or trade the contract prior to its maturity. The rescission of EITF 98-10 and the issuance of EITF 02-03 will not require any change to the Company's current accounting treatment for revenues or gains or losses from derivative activities.

In November 2002, the FASB issued Interpretation No. 45 ("FIN 45"), "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN 45 requires that a liability be recorded in the guarantor's balance sheet upon issuance of a guarantee. FIN 45 also requires additional disclosures about the guarantees an entity has issued. The Company will apply the recognition provisions of FIN 45 prospectively to guarantees issued or modified after December 31, 2002. The disclosure requirements are effective for the Company's financial statements for the year ending December 31, 2002. The Company is currently evaluating the potential impact that the recognition provisions of FIN 45 will have on its consolidated financial condition and results of operations.

In January 2003, the FASB issued Interpretation No. 46 ("FIN 46"), "Consolidation of Variable Interest Entities." FIN 46 provides guidance on how to identify a variable interest entity ("VIE") and determine when the assets, liabilities, and results of operations of a VIE need to be included in a company's consolidated financial statements. FIN 46 also requires additional disclosures by primary beneficiaries and other significant variable interest holders in a VIE. The provisions of FIN 46 are effective immediately for all VIEs created after January 31, 2003. For VIEs created before February 1, 2003, the provisions of FIN 46 must be adopted at the beginning of the first interim or annual reporting period beginning after June 15, 2003. While the Company is currently evaluating the potential impact of the adoption of FIN 46, the Company believes that it will not be subject to the consolidation or disclosure requirements of FIN 46.

***Reclassifications.*** Certain prior years' amounts in the consolidated financial statements and related notes have been reclassified to conform to the presentation used in 2002.

## NOTE 3 - RELATED PARTIES

From time to time, the Company enters into joint ventures and partnerships in order to reduce risk, create strategic alliances and to establish itself in oil and gas producing basins in the United States. All transactions entered into by the Company with its related parties were consummated in the ordinary course of business and on terms that would be comparable to those obtained from third parties.

***Fort Union.*** In December 1998, the Company joined with other industry participants to form the Fort Union Gas Gathering, L.L.C. ('Fort Union"), to construct a gathering pipeline and treater in the Powder River Basin in northeast Wyoming. At December 31, 2002 and 2001, the Company owned an approximate 13% interest in Fort Union and is the construction manager and field operator. Construction of the gathering header and treating system was project financed by Fort Union and required a cash investment by the Company of approximately $900,000. In 1999, the Company entered into a ten-year agreement for firm gathering services on 60 MMcf per day of capacity for $0.14 per Mcf on Fort Union. In 2001, Fort Union was expanded. The expansion costs totaled approximately $22.0 million and were again project financed by Fort Union. This debt is amortizing on an annual basis and is scheduled to be fully paid in 2009. In the fourth quarter of 2001, the Company made an additional equity contribution to Fort Union of approximately $500,000. Also in connection with the expansion, the Company increased its commitment for firm gathering services to a total of 83 MMcf per day of capacity at $0.14 per Mcf. All participants in Fort Union have guaranteed Fort Union's payment of the project financing on a proportional basis resulting in the Company's guarantee of $6.3 million of the debt of Fort Union. This guarantee is not reflected on the Consolidated Balance Sheet. The Company acts as field operator of Fort Union and charges a monthly overhead fee to cover such services. In 2002, 2001 and 2000, the Company received overhead fees from Fort Union totaling $507,000, $483,000 and $72,000, respectively, and the Company paid to Fort Union a total of $5.3 million, $3.3 million and $3.1 million for gathering services, respectively. At December 31, 2002 and 2001, the Company had a net amount due to Fort Union of $258,000 and $76,000, respectively.

*Rendezvous.* At December 31, 2002 and 2001, the Company owned a 50% interest in Rendezvous Gas Services, L.L.C and the Company serves as field operator of its systems. Rendezvous was formed in 2001 to gather gas for the Company and other third parties along the Pinedale Anticline for blending or processing at either the Company's Granger Complex or at a third-party owned processing facility. Rendezvous was expanded during 2002 and 2001, and at December 31, 2002, the Company had a total of $22.8 million invested in this venture. The Company charges a monthly overhead fee to act as field operator of Rendezvous. In 2002 and 2001, the Company received overhead fees from Rendezvous totaling $100,000 and $25,000, respectively, and the Company paid to Rendezvous a total of $2.2 million in 2002 for gathering services. The Company paid no fees for gathering in 2001. At December 31, 2002 and 2001, the Company had a net amount due to Rendezvous of $3.6 million and $126,000, respectively.

*Westana.* In prior years, the Company had a 50% ownership interest in Westana Gathering Company ("Westana"). This joint venture gathered natural gas for third parties in Oklahoma. In February 2000, the Company acquired the remaining 50% interest in the Westana Gathering Company for a net purchase price of $9.8 million and Westana was dissolved. The Company acted as operator of Westana and charged a monthly overhead fee to cover such services. In 2000, the Company received overhead fees from Westana totaling $62,000.

*Officer Transactions.* The Company has entered into agreements committing the Company to loan to certain key employees an amount sufficient to exercise their options as each portion of their options vests under the Key Employees' Incentive Stock Option Plan. The loan and accrued interest will be forgiven if the employee is continually employed by the Company and upon a resolution of the board of directors. In May, July and December 2002, the Company forgave loans related to 62,500 shares of Common Stock totaling $703,000. Pursuant to the terms of an agreement entered into in 2001, the remaining loan will be forgiven in May 2003. There were no loans forgiven in 2001 or 2000. As of December 31, 2002 and 2001, loans related to 27,500 and 75,000 shares of Common Stock totaling $295,000 and $803,000, respectively, were outstanding under these programs. The remaining loan is secured by a portion of the Common Stock issued upon exercise of the options and are accounted for as a reduction of stockholders' equity. In prior years, the Company has reserved for the forgiveness of these loans.

In October 2001, Mr. Lanny Outlaw, our former Chief Executive Officer and President, retired. The Company has entered into a consulting agreement with Mr. Outlaw providing for payments of $167,000 in May 2002 and $175,000 in May 2003.

## NOTE 4 - COMMODITY RISK MANAGEMENT

*Risk Management Activities.* The Company's commodity price risk management program has two primary objectives. The first goal is to preserve and enhance the value of the Company's equity volumes of gas and NGLs with regard to the impact of commodity price movements on cash flow, net income and earnings per share in relation to those anticipated by the Company's operating budget. The second goal is to manage price risk related to the Company's physical gas, crude oil and NGL marketing activities to protect profit margins. This risk relates to fixed price purchase and sale commitments, the value of storage inventories and exposure to physical market price volatility.

The Company utilizes a combination of fixed price forward contracts, exchange-traded futures and options, as well as fixed index swaps, basis swaps and options traded in the over-the-counter market ("OTC") to accomplish these objectives. These instruments allow the Company to preserve value and protect margins because corresponding losses or gains in the value of the financial instruments offset gains or losses in the physical market.

The Company uses futures, swaps and options to reduce price risk and basis risk. Basis is the difference in price between the physical commodity being hedged and the price of the futures contract used for hedging. Basis risk is the risk that an adverse change in the futures market will not be completely offset by an equal and opposite change in the cash price of the commodity being hedged. Basis risk exists in natural gas primarily due to the geographic price differentials between cash market locations and futures contract delivery locations.

The Company enters into futures transactions on the New York Mercantile Exchange ("NYMEX") and through OTC swaps and options with various counter parties, consisting primarily of financial institutions and other natural gas companies. The Company conducts its standard credit review of OTC counter parties and has agreements with many of these parties that contain collateral requirements. The Company generally uses standardized swap agreements that allow for offset of positive and negative exposures. OTC exposure is marked-to-market daily for the credit review process. The Company's OTC credit risk exposure is partially limited by its ability to require a margin deposit from its major counter parties based upon the mark-to-market value of their net exposure. The Company is subject to margin deposit requirements under these same agreements. In addition, the Company is subject to similar margin deposit requirements for its NYMEX counter parties related to its net exposures. At December 31, 2002, the Company had posted margin totaling $19.6 million with various counter parties.

The use of financial instruments may expose the Company to the risk of financial loss in certain circumstances, including instances when (i) equity volumes are less than expected, (ii) the Company's customers fail to purchase or deliver the contracted quantities of natural gas or NGLs, or (iii) the Company's OTC counter parties fail to perform. To the extent that the Company engages in hedging activities, it may be prevented from realizing the benefits of favorable price changes in the physical market. However, it is similarly insulated against decreases in such prices.

For 2003, the Company has hedged approximately 53% of its projected equity natural gas volumes and approximately 78% of its estimated equity production of crude oil, condensate, and NGLs. These contracts are designated and accounted for as cash flow hedges. As such, gains and losses related to the effective portions of the changes in the fair value of the derivatives are recorded in Accumulated other comprehensive income, a component of Stockholders' equity. Any gains or losses on these cash flow hedges are recognized in the Consolidated Statement of Operations through Product purchases when the hedged transactions occur. Gains or losses from the ineffective portions of changes in the fair value of cash flow hedges are recognized currently in earnings through Non-cash change in the fair value of derivatives. This ineffectiveness is primarily due to the use of crude oil swaps in hedging the variability in the sales price of butanes. During 2002 the Company recognized a total of $154,000 of losses from the ineffective portions of its hedges. There were no ineffective portions of its hedges recognized in 2001. Overall, the Company's hedges are expected to continue to be "highly effective" under SFAS 133 in the future. In the fourth quarter of 2002, in order to properly align the Company's hedged volumes of natural gas to its forecasted equity production for 2003, the Company discontinued hedge treatment on financial instruments for 6 MMcf per day. As a result, a pre-tax gain of $790,000 was reclassified into earnings in the fourth quarter of 2002 from accumulated other comprehensive income. There were no gains or losses reclassified into earnings as a result of the discontinuance of cash flow hedges in either 2001 or 2000.

To qualify as cash flow hedges, the hedge instruments must be designated as cash flow hedges and changes in their fair value must correlate with changes in the price of the forecasted transaction being hedged so that the Company's exposure to the risk of commodity price changes is reduced. To meet this requirement, the Company hedges both the price of the commodity and the basis between that derivative's contract delivery location and the cash market location used for the actual sale of the product. This structure attains a high level of effectiveness, insuring that a change in the price of the forecasted transaction will result in an equal and opposite change in the cash price of the hedged commodity. The Company utilizes crude oil as a surrogate hedge for butanes. This typically results in an effective hedge as crude oil and butane prices historically have moved in tandem.

Account balances related to equity hedging transactions at December 31, 2002 were $11.8 million in Current Assets from price risk management activities, $20.1 million in Current Liabilities from price risk management activities, ($3.1) million in Deferred income taxes payable, net, and a $5.4 million after-tax unrealized loss in Accumulated other comprehensive income, a component of Shareholders' Equity. Based on the commodity prices as of December 31, 2002, the after-tax loss of $5.4 million will be re-classified from Accumulated other comprehensive income to Product Purchases during the next twelve months.

*Natural Gas Derivative Market Risk.* As of December 31, 2002, the Company held a notional quantity of approximately 303 Bcf of natural gas futures, swaps and options extending from January 2003 to October 2006 with a weighted average duration of approximately six months. This was comprised of approximately 116 Bcf of long positions and 187 Bcf of short positions in these instruments. As of December 31, 2001, the Company held a notional quantity of approximately 439 Bcf of natural gas futures, swaps and options extending from January 2002 to October 2006 with a weighted average duration of approximately six months. This was comprised of approximately 199 Bcf of long positions and 240 Bcf of short positions in these instruments.

*Crude Oil and NGL Derivative Market Risk.* As of December 31, 2002, the Company held a notional quantity of approximately 275,940 MGal of NGL futures, swaps and options extending from January 2003 to December 2003 with a weighted average duration of approximately six months. This was comprised of approximately 138,600 MGal of long positions and 137,340 MGal of short positions in these instruments. As of December 31, 2001, the Company held a notional quantity of approximately 131,124 MGal of NGL futures, swaps and options extending from January 2002 to December 2002 with a weighted average duration of approximately six months. This was comprised of approximately 61,824 MGal of long positions and 69,300 MGal of short positions in these instruments.

As of December 31, 2002, the Company did not hold any NGL futures, swaps or options for settlement beyond 2003. As of December 31, 2002, the estimated fair value of the aforementioned crude oil and NGL options held by the Company was approximately $(2.8) million.

*Foreign Currency Derivative Market Risk.* As a normal part of our business, the Company enters into physical gas transactions which are payable in Canadian dollars. The Company enters into forward purchases and sales of Canadian dollars from time to time to fix the cost of its future Canadian dollar denominated natural gas purchase, sale, storage and transportation obligations. This is done to protect marketing margins from adverse changes in the U.S. and Canadian dollar exchange rate between the time the commitment for the payment obligation is made and the actual payment date of such obligation. As of December 31, 2002, the net notional value of such contracts was approximately $14.4 million in Canadian dollars, which approximated fair market value. As of December 31, 2001, the net notional value of such contracts was approximately $12.7 million in Canadian dollars, which again approximated its fair market value.

## NOTE 5 - DEBT

The following summarizes the Company's consolidated debt at the dates indicated (000s):

| | December 31, 2002 | December 31, 2001 |
|---|---|---|
| Master Shelf and Subordinated Notes | $ 263,333 | $ 271,666 |
| Variable Rate Revolving Credit Facility | 96,600 | 95,001 |
| Total long-term debt | $ 359,933 | $ 366,667 |

*Revolving Credit Facility.* The Revolving Credit Facility is with a syndicate of banks and provides for a maximum borrowing commitment of $250 million consisting of an $83 million 364-day Revolving Credit Facility, or Tranche A, and a $167 million Revolving Credit Facility, or Tranche B, which matures on March 31, 2004. At December 31, 2002, $96.6 million was outstanding under this facility. The Revolving Credit Facility bears interest at certain spreads over the Eurodollar rate, or the greater of the Federal Funds rate or the agent bank's prime rate. The Company has the option to determine which rate will be used. The Company also pays a facility fee on the commitment. The interest rate spreads and facility fee are adjusted based on its debt to capitalization ratio and range from .75% to 2.00%. At December 31, 2002, the interest rate payable on borrowings under this facility was 2.6%. The Company is required to maintain a total debt to capitalization ratio of not more than 55%, and a senior debt to capitalization ratio of not more than 35%. The agreement also requires a quarterly test of the ratio of EBITDA (excluding some non-recurring items) for the last four quarters, to interest and dividends on preferred stock for the same period. The ratio must exceed 3.25 to 1.0. This facility also limits the Company's ability to enter into operating and sale-leaseback transactions. This facility is guaranteed and secured via a pledge of the stock of all of its material subsidiaries.

*Master Shelf Agreement.* In December 1991, the Company entered into a Master Shelf Agreement with The Prudential Insurance Company of America. Amounts outstanding under the Master Shelf Agreement at December 31, 2002 are as indicated in the following table (000s):

| Issue Date | Amount | Interest Rate | Final Maturity | Principal Payments Due |
|---|---|---|---|---|
| October 27, 1992 | $ 8,333 | 7.99% | October 27, 2003 | single payment at maturity |
| December 27, 1993 | 25,000 | 7.23% | December 27, 2003 | single payment at maturity |
| October 27, 1994 | 25,000 | 9.24% | October 27, 2004 | single payment at maturity |
| July 28, 1995 | 50,000 | 7.61% | July 28, 2007 | $10,000 on each of July 28, 2003 through 2007 |
| | $108,333 | | | |

Under the Company's agreement with Prudential, it is required to maintain a current ratio, as defined therein, of at least .9 to 1.0, a minimum tangible net worth equal to the sum of $300 million plus 50% of consolidated net earnings earned from January 1, 1999 plus 75% of the net proceeds of any equity offerings after January 1, 1999, a total debt to capitalization ratio of not more than 55% and a senior debt to capitalization ratio of not more than 35%. This agreement also requires an EBITDA to interest ratio of not less than 3.75 to 1.0 and an EBITDA to interest on senior debt ratio of not less than 5.50 to 1.0. EBITDA in these calculations excludes certain non-recurring items. In addition, this agreement contains a calculation limiting dividends and other restricted payments including preferred stock redemptions. Under this limitation, approximately $78.3 million was available for restricted payments at December

31, 2002. This facility also limits the Company's ability to enter into operating and sale-leaseback transactions. The Company is currently paying an annual fee of 0.50% on the amounts outstanding on the Master Shelf Agreement. This fee will continue until it receives an implied investment grade rating on its senior secured debt from Moody's Investors Service or Standard & Poor's. Borrowings under the Master Shelf Agreement are guaranteed by, and secured via, a pledge of the stock of all of its material subsidiaries.

In October 2002, the Company funded a required principal repayment under the Master Shelf Agreement of $8.3 million with funds available under the Revolving Credit Facility. During 2003, the Company is required to make principal payments totaling $43.3 million and intends to fund these with amounts available under the Revolving Credit Facility.

***Senior Subordinated Notes.*** In 1999, the Company sold $155.0 million of Senior Subordinated Notes in a private placement with a final maturity of 2009 due in a single payment which were subsequently exchanged for registered publicly tradeable notes under the same terms and conditions. The Senior Subordinated Notes bear interest at 10% per annum and were priced at 99.225% to yield 10.125%. These notes contain maintenance covenants that include limitations on debt incurrence, restricted payments, liens and sales of assets. Under the calculation limiting restricted payments, including common dividends, approximately $42.8 million was available at December 31, 2002. The Senior Subordinated Notes are unsecured and are guaranteed on a subordinated basis by all the Company's material subsidiaries. The Company incurred approximately $5.0 million in offering commissions and expenses, which were capitalized and are being amortized over the term of the notes.

***Covenant Compliance.*** The Company was in compliance with all covenants in its debt agreements at December 31, 2002. Taking into account all the covenants contained in these agreements, the Company had approximately $115.0 million of available borrowing capacity at December 31, 2002. None of our credit facilities include covenant requirements or acceleration provisions based upon a change in our credit ratings.

Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2002 (000s):

| | |
|---|---|
| 2003 | $ 43,333 |
| 2004 | 131,600 |
| 2005 | 10,000 |
| 2006 | 10,000 |
| 2007 | 10,000 |
| Thereafter | 155,000 |
| Total | $ 359,933 |

## NOTE 6 - FINANCIAL INSTRUMENTS

The Company using available market information and valuation methodologies has determined the estimated fair values of the Company's financial instruments. Considerable judgment is required to develop the estimates of fair value; thus, the estimates provided herein are not necessarily indicative of the amount that the Company could realize upon the sale or refinancing of such financial instruments.

| | December 31, 2002 | | December 31, 2001 | |
|---|---|---|---|---|
| | Carrying Value | Fair Value | Carrying Value | Fair Value |
| | (000s) | | (000s) | |
| Cash and cash equivalents | $ 7,312 | $ 7,312 | $ 10,032 | $ 10,032 |
| Trade accounts receivable | 253,587 | 253,587 | 220,537 | 220,537 |
| Accounts payable | 242,987 | 242,987 | 260,208 | 260,208 |
| Long-term debt | 359,933 | 365,190 | 366,667 | 370,329 |
| Derivative contracts | $ 63 | $ 63 | $ 49,411 | $ 49,411 |

The Company in estimating the fair value of its financial instruments used the following methods and assumptions:

***Cash and cash equivalents, trade accounts receivable and accounts payable.*** Due to the short-term nature of these instruments, the carrying value approximates the fair value.

*Long-term debt.* The Company's long-term debt was primarily comprised of fixed rate facilities. Fair market value for this debt was estimated using discounted cash flows based upon the Company's current borrowing rates for debt with similar maturities. The remaining portion of the long-term debt was borrowed on a revolving basis, which accrues interest at current rates; as a result, carrying value approximates fair value of this outstanding debt.

*Derivative contracts.* Fair value represents the amount at which the instrument could be exchanged in a current arms-length transaction.

## NOTE 7 - INCOME TAXES

The provision for income taxes for the years ended December 31, 2002, 2001 and 2000, excluding the tax effect of the extraordinary items, is comprised of (000s):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Current: | | | |
| Federal | $ 9,404 | $ 14,074 | $ 250 |
| State | 1,096 | (400) | 600 |
| Total Current | 10,500 | 13,674 | 850 |
| Deferred: | | | |
| Federal | 18,967 | 41,225 | 31,497 |
| State | 647 | 1,590 | 1,215 |
| Total Deferred | 19,614 | 42,815 | 32,712 |
| Total tax provision (benefit) | $ 30,114 | $ 56,489 | $ 33,562 |

The tax benefit allocated to the extraordinary charges was $997,000 for the year ended December 31, 2000. There were no extraordinary charges in 2002 or 2001.

Temporary differences and carry-forwards which give rise to the deferred tax liabilities (assets) at December 31, 2002 and 2001, net of the tax effect of the extraordinary items, are as follows (000s):

| | 2002 | 2001 |
|---|---|---|
| Property and equipment | $ 175,164 | $ 167,663 |
| Differences between the book and tax basis of acquired assets | 12,101 | 11,560 |
| Hedging derivatives | (3,118) | 9,835 |
| Total deferred income tax liabilities | 184,147 | 189,058 |
| Alternative Minimum Tax ("AMT") credit carry-forwards | (46,076) | (36,672) |
| Net Operating Loss ("NOL") carry-forwards | (13,818) | (33,640) |
| Total deferred income tax assets | (59,894) | (70,312) |
| Net deferred income taxes payable | $ 124,253 | $ 118,746 |

The change in the net deferred income taxes in 2002 and 2001 includes a $1.2 million and $1.6 million tax benefit, respectively, associated with the exercise of incentive stock options. The Company expects to realize such tax benefit.

The differences between the provision for income taxes at the statutory rate and the actual provision for income taxes, before the tax effect of extraordinary items, for the years ended December 31, 2002, 2001 and 2000 are summarized as follows (000s):

| | 2002 | % | 2001 | % | 2000 | % |
|---|---|---|---|---|---|---|
| Income tax before effect of extraordinary item at statutory rate | $ 28,246 | 35.0 | $ 53,245 | 35.0 | $ 31,984 | 35.0 |
| State income taxes, net of federal benefit | 968 | 1.2 | 2,130 | 1.4 | 1,280 | 1.4 |
| Canada income taxes, effect of disallowed loss on sale of stock and other miscellaneous items | 900 | 1.1 | 1,114 | .7 | 298 | .3 |
| Total | $ 30,114 | 37.3 | $ 56,489 | 37.1 | $ 33,562 | 36.7 |

At December 31, 2002, the Company had NOL carry-forwards for federal and state income tax purposes and AMT credit carry-forwards for federal income tax purposes of approximately $38.2 million and $46.1 million, respectively. These carry-forwards expire as follows (000s):

| Expiration Dates | NOL | AMT |
|---|---|---|
| 2018 | $ 38,175 | $ - |
| No expiration | - | 46,076 |
| Total | $ 38,175 | $ 46,076 |

The Company believes that the NOL carry-forwards and AMT credit carry-forwards will be utilized prior to their expiration because they are substantially offset by existing taxable temporary differences reversing within the carry-forward period or are expected to be realized by achieving future profitable operations based on the Company's dedicated and owned reserves, past earnings history and projections of future earnings.

## NOTE 8 - COMMITMENTS AND CONTINGENT LIABILITIES

*Litigation.*

***Western Gas Resources, Inc. and Lance Oil & Gas Company, Inc. (together the Plaintiffs) v. Williams Production RMT Company., (Defendant), Civil Action No. CO2-10-394, District Court, County of Sheridan, Wyoming.*** On October 23, 2002, Plaintiffs filed a complaint for declaratory relief and damages related to a dispute arising under a Development Agreement, a Purchase and Sale Agreement and an Operating Agreement (collectively, the "Agreements") between the Plaintiffs and Barrett Resources Corporation, or Barrett, dated on or about October 30, 1997, as each may have been amended. The dispute centers on Defendant's acquisition of Barrett by merger consummated on August 2, 2001. Plaintiffs allege that they were entitled to a preferential right to purchase certain properties of Barrett located in the Powder River Basin of Wyoming under the Agreements and that Plaintiffs' consent was required prior to Barrett's assignment of its interests in the Agreements to the Defendant. Plaintiffs also allege that Barrett (now Defendant) should no longer be the operator of these properties as a consequence of the merger transaction.

In the fourth quarter of 2002, the Defendant asserted breach of contract claims against the Company. The Defendant also claimed damages under its gathering agreement with the Company. The Company believes that the Defendant's assertions have no merit. The Company has also asserted breach of contract claims against the Defendant for its operating practices. The parties have agreed to begin mediation of these issues in the first quarter of 2003. At this time, the Company is unable to predict the outcome of this litigation or the claims scheduled for mediation.

***Western Gas Resources, Inc. v. Amerada Hess Corporation, District Court, Denver County, Colorado, Civil Action No. 00-CV-1433.*** The Company was a defendant in prior litigation, styled as *Berco Resources, Inc. v. Amerada Hess Corporation and Western Gas Resources, Inc., United States District Court, District of Colorado, Civil Action No. 97-WM-1332,* which was settled in 2000 for an amount which did not have a material impact on the Company's results of operations or financial position. The Company is seeking reimbursement from Amerada Hess under a contractual indemnity. The Company has amended its original complaint and requested a jury trial in this case. Both parties filed cross motions for summary judgment. On April 19, 2002, the trial court ruled on the parties' cross motions for summary judgment in favor of Amerada Hess, indicating that Amerada Hess has no obligation to indemnify the Company in this matter. On May 31, 2002, the Company appealed the trial court decision to the Colorado Court of Appeals. Amerada Hess filed a motion to dismiss the appeal, which was denied by the Colorado Court of Appeals on July 29, 2002. All briefs by the parties have been filed and the parties are awaiting a decision. At this time, the Company is unable to predict the outcome of this appeal.

*United States of America and ex rel. Jack J. Grynberg v. Western Gas Resources, Inc., et al., United States District Court, District of Colorado, Civil Action No. 97-D-1427.* The Company is a defendant in litigation, along with 300 natural gas companies in 74 separate actions filed by Mr. Grynberg on behalf of the federal government. The allegations made by Mr. Grynberg are that established gas measurement and royalty calculation practices improperly deprived the federal government of appropriate natural gas royalties and violate 31 U. S. C. 3729 (a) (7) of the False Claims Act. The cases have been consolidated to the United States District Court for the District of Wyoming. Discovery is in the initial stages to determine if this matter qualifies as a qui tam (or class) action. On October 9, 2002, the court dismissed Mr. Grynberg's valuation claims, and he has appealed this decision. The Company believes that Mr. Grynberg's claims are baseless and without merit and intends to vigorously contest the allegations in this case. At this time, the Company is unable to predict the outcome of this matter.

*Price, et al. v. Gas Pipelines, Western Gas Resources, Inc., et al., District Court, Stevens County, Kansas, Case No. 99-C-30.* The Company is a defendant in litigation, along with numerous other natural gas companies, in which Mr. Price is claiming an under measurement of gas and Btu volumes throughout the country. The Company along with other natural gas companies filed a motion to dismiss for failure to state a claim. The court denied these motions to dismiss. On January 13, 2003, a hearing was held to determine whether this matter could be certified as a class action. The Company is awaiting the court's decision on the class certification. The Company believes that Mr. Price's claims are baseless and without merit and intends to vigorously contest the allegations in this case. At this time, the Company is unable to predict the outcome of this matter.

*Texas Natural Resource Conservation Commission (TNRCC)-Notification of Enforcement and Notification of Alleged Violations, Gomez Field Gathering Station, Fort Stockton, Texas.* On October 28, 2002, the Company received a Notice of Enforcement for an alleged violation that a compliance certification during the period of December 30, 2000 through December 29, 2001 was not timely filed under its general operating permit requirements. The Company also received three Notices of Violations on October 18, 2002, for alleged failure to timely submit Permit Compliance Certifications for the period of April 2, 2000 through April 1, 2001 within thirty days and sixty days from the applicable deadlines, and a Notice of Violation for not submitting a deviation report, as required under Title V for the late submittals, for the period of April 2,2000 through October 10, 2001. The Company has complied with all certification requirements with no penalties assessed.

*Texas Natural Resource Conservation Commission (TNRCC) –Notification of Alleged Violations, Gomez Treating Plant, Texas.* On December 5, 2001, the Company received notification of an alleged violation associated with compliance certifications for a treating plant owned by an unaffiliated company. The Company has contested the alleged violation on the basis that it never purchased this treating facility and the unaffiliated company had physically removed the facility in 1995. At this time, the Company is unable to quantify penalties or fines, if any, associated with this alleged violation.

*Retirement Plan.* The Company's retirement plan for its employees includes a fund, which allows them to invest in the Company's common stock. The fund manager, Fidelity Investments, purchases this stock in open market transactions. Under SEC rules, the stock purchased by the plan participants during a portion of 2001and 2002 may be required to be registered by the Company. To resolve this issue, the Company intends to file a registration statement on Form S-3 with the SEC and offer to rescind or pay damages related to certain employee-initiated transactions during that period. Any stock acquired by the Company through this rescission offer will be treated as treasury stock. While the Company is unable to estimate the cost or results of the rescission offer, it does not expect the costs to have a material adverse effect on its financial position or results of operations.

*Other Litigation.* The Company is involved in various other litigation and administrative proceedings arising in the normal course of business. In the opinion of the Company's management, any liabilities that may result from these claims will not, individually or in the aggregate have a material adverse effect on the Company's financial position or results of operations.

*Commitments.*

*Lease Commitments.* As a normal course of the Company's business operations, the Company enters into operating leases for office space, office equipment, communication equipment and transportation equipment. In addition, primarily to support its growing development in the Powder River Basin coal bed development, the Company has entered into operating leases for compression equipment. These leases are classified as operating leases and have terms ranging from two to ten years. The majority of the leases for compression have purchase options at various times throughout the primary terms of the agreements and has renewal provisions. Rental payments under operating leases have totaled $10.8 million, $3.1 million and $3.4 million in 2002, 2001 and 2000, respectively. Future operating lease payments by year under these leases are as follows (000s):

| | | |
|---|---|---|
| 2003 | $ | 12,902 |
| 2004 | | 9,657 |
| 2005 | | 9,227 |
| 2006 | | 8,845 |
| 2007 | | 8,029 |
| Thereafter | | 13,026 |
| Total | $ | 61,686 |

***Firm Transportation Capacity.*** The Company enters into firm transportation agreements with interstate pipeline companies as parts of its marketing operations and to ensure that its equity production has access to downstream markets. These agreements have terms ranging from one month to fourteen years. Payments under these agreements have totaled $29.2 million, $8.8 million and $15.7 million in 2002, 2001 and 2000, respectively. Future payments by year under these agreements are as follows (000s):

| | | |
|---|---|---|
| 2003 | $ | 26,411 |
| 2004 | | 25,000 |
| 2005 | | 24,913 |
| 2006 | | 24,732 |
| 2007 | | 23,773 |
| Thereafter | | 104,099 |
| Total | $ | 228,928 |

***Storage Capacity.*** The Company enters into storage agreements with various third parties primarily as part of its marketing operations. To the extent that these contracts are in support of its marketing operations, the agreements are classified as derivatives in accordance with SFAS No. 133 and the difference between fair value and cost is included in income. Payments under these agreements have totaled $5.1 million, $3.9 million and $6.2 million in 2002, 2001 and 2000, respectively. As of December 31, 2002, the Company had contracts in place for approximately 20.2 Bcf of storage capacity at various third-party facilities. The associated contract periods have an average term of seventeen months. Future payments by year under these agreements are as follows (000s):

| | | |
|---|---|---|
| 2003 | $ | 5,240 |
| 2004 | | 4,384 |
| 2005 | | 3,193 |
| 2006 | | 2,783 |
| 2007 | | 2,582 |
| Thereafter | | 10,451 |
| Total | $ | 28,633 |

## NOTE 9 - BUSINESS SEGMENTS AND RELATED INFORMATION

The Company operates in four principal business segments, as follows: Gas Gathering, Processing and Treating; Exploration and Production; Marketing; and Transportation. Management separately monitors these segments for performance against its internal forecast and these segments are consistent with the Company's internal financial reporting package. These segments have been identified based upon the differing products and services, regulatory environment and the expertise required for these operations.

***Gas Gathering, Processing and Treating.*** In this segment, the Company connects producers' wells (including those of the Exploration and Production segment) to its gathering systems for delivery to its processing or treating plants, process the natural gas to extract NGLs and treat the natural gas in order to meet pipeline specifications. In certain areas, where no processing is required, the Company gathers and compresses producers' gas and delivers it to pipelines. Except for volumes taken in kind by its producers, the Marketing segment sells the residue gas and NGLs extracted at most of its facilities. In this segment, the Company recognizes revenue for its services at the time the service is performed.

Substantially all gas flowing through the Company's gathering, processing and treating facilities is supplied under three types of contracts providing for the purchase, treating or processing of natural gas for periods ranging from one month to twenty years or in some cases for the life of the oil and gas lease. Approximately 65% of the Company's plant facilities' gross margins, or revenues at the plants less product purchases, for the month of December 2002 resulted from percentage-of-proceeds agreements in which it is typically responsible for the marketing of the gas and NGLs. The Company pays producers a specified percentage of the net proceeds received from the sale of the gas and the NGLs.

Approximately 21% of the Company's plant facilities' gross margins for the month of December 2002 resulted from contracts that are primarily fee-based from which it receives a set fee for each Mcf of gas gathered and/or processed. This type of contract provides the Company with a steady revenue stream that is not dependent on commodity prices, except to the extent that low prices may cause a producer to delay drilling.

Approximately 14% of the Company's plant facilities' gross margins for the month of December 2002 resulted from contracts that combine gathering, compression or processing fees with "keepwhole" arrangements or wellhead purchase contracts. Typically, the Company charges producers a gathering and compression fee based upon volume. In addition, the Company retains the NGLs recovered by the processing facility and keeps the producers whole by returning to the producers at the tailgate of the plant an amount of residue gas equal on a Btu basis to the natural gas received at the plant inlet. The "keepwhole" component of the contracts permits the Company to benefit when the value of the NGLs is greater as a liquid than as a portion of the residue gas stream. However, the Company is adversely affected when the value of the NGLs is lower as a liquid than as a portion of the residue gas stream.

*Exploration and Production.* The activities of the Exploration and Production segment include the exploration and development of gas properties primarily in the Rocky Mountain basins including those where the Company's gathering and/or processing facilities are located. The Marketing segment sells the majority of the production from these properties.

*Marketing.* The Company's Marketing segment buys and sells gas and NGLs in the United States and Canada from and to a variety of customers. The marketing of products purchased from third parties typically results in low operating margins relative to the sales price. In addition, this segment also markets gas and NGLs produced by the Company's gathering, processing, treating and production assets. Also included in this segment are its Canadian marketing operations (which are immaterial for separate presentation). In this segment, revenues for sales of product are recognized at the time the gas or NGLs are delivered to the customer and are sensitive to changes in the market prices of the underlying commodities. The Company sells its products under agreements with varying terms and conditions in order to match seasonal and other changes in demand. Its gas sales contracts have an average duration of 15 months. The Company records revenue on its gas and NGL marketing activities on a gross sales versus sales net of purchases basis as it obtains title to all of the gas and NGLs that it buys including third-party purchases, and bears the risk of loss and credit exposure on these transactions. Additionally, for its marketing activities the Company utilizes mark-to-market accounting. Under mark-to-market accounting, the expected margin to be realized over the term of the transaction is recorded in the month of origination. To the extent that a transaction is not fully hedged or there is any hedge ineffectiveness, additional gains or losses associated with the transaction may be reported in future periods.

*Transportation.* The Transportation segment reflects the operations of the Company's MIGC and MGTC pipelines. The majority of the revenue presented in this segment is derived from transportation of residue gas for its Marketing segment and other third parties. In this segment, the Company realizes revenue on a monthly basis from firm capacity contracts under which the shipper pays for transport capacity whether or not the capacity is used and from interruptible contracts where a fee is charged based upon volumes received into the pipeline. The Transportation segments' firm capacity contracts range in duration from one month to six years.

The following table sets forth the Company's segment information as of and for the three years ended December 31, 2002, 2001 and 2000 (000s). Due to the Company's integrated operations, the use of allocations in the determination of business segment information is necessary. Inter-segment revenues are valued at prices comparable to those of unaffiliated customers.

| | Gas Gathering and Processing | Exploration and Production | Marketing | Trans-portation | Corporate | Elim-inating Entries | Total |
|---|---|---|---|---|---|---|---|
| **Year Ended December 31, 2002** | | | | | | | |
| Revenues from unaffiliated customers | | | | | | | |
| Sale of gas | $ 2,155 | $ 1,497 | $ 2,090,480 | $ 1,252 | $ - | $ - | $ 2,095,384 |
| Sale of natural gas liquids | 17 | - | 317,927 | - | | | 317,944 |
| Equity hedges: | | | | | | | |
| Residue | 3,238 | 24,846 | - | - | - | - | 28,084 |
| Liquids | (8,247) | - | - | - | - | - | (8,247) |
| Gathering, processing and transportation revenue | 57,298 | - | - | 8,303 | - | - | 65,601 |
| Total revenues from unaffiliated | 54,461 | 26,343 | 2,408,407 | 9,555 | - | - | 2,498,766 |
| Inter-segment sales | 638,739 | 112,943 | 23,657 | 15,794 | 54 | (791,187) | - |
| Non-cash change in fair value | | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| of derivatives | (233) | 589 | (14,144) | - | - | - | (13,788) |
| Interest income | - | 43 | 10 | 1 | 8,803 | (8,612) | 245 |
| Other, net | 2,843 | 45 | 6 | (567) | (415) | 2,563 | 4,475 |
| Total revenues | 695,810 | 139,963 | 2,417,936 | 24,783 | 8,442 | (797,236) | 2,489,698 |
| Product purchases | 533,515 | 3,080 | 2,380,446 | - | - | (759,862) | 2,157,179 |
| Plant operating and transportation expense | 73,878 | - | - | 9,068 | - | (1,416) | 81,530 |
| Oil and gas exploration and production expense | - | 63,149 | - | - | - | (29,142) | 34,007 |
| Earnings from equity investments | (4,453) | - | - | - | - | - | (4,453) |
| Operating profit | 92,870 | 73,734 | 37,490 | 15,715 | 8,442 | (6,816) | 221,435 |
| | | | | | | | |
| Depreciation, depletion and amortization | 39,792 | 28,937 | 157 | 1,675 | 6,444 | - | 77,005 |
| Selling and administrative expense | 15,836 | 9,745 | 7,309 | 2,938 | - | - | 35,828 |
| (Gain) loss from sale of assets | 1,102 | (323) | - | 476 | 267 | (574) | 948 |
| Interest expense | - | - | - | - | 26,951 | - | 26,951 |
| Segment profit | $ 36,140 | $ 35,375 | $ 30,024 | $ 10,626 | $(25,220) | $ (6,242) | $ 80,703 |
| | | | | | | | |
| Identifiable assets | | | | | | | |
| Other allocated assets | $ 19,457 | $ 3,429 | $ 117,167 | $ 1,064 | $ 279,473 | $ (52,001) | $ 368,589 |
| Investment in others | 2,839 | - | - | 3,802 | 55,509 | (33,022) | 29,128 |
| Capital assets | 587,244 | 221,160 | 1,672 | 42,077 | 52,267 | 7 | 904,427 |
| Total identifiable assets | $ 609,540 | $ 224,589 | $ 118,839 | $ 46,943 | $ 387,249 | $ (85,016) | $ 1,302,144 |

| | Gas Gathering and Processing | Exploration and Production | Marketing | Trans-portation | Corporate | Elim-inating Entries | Total |
|---|---|---|---|---|---|---|---|
| **Year ended December 31, 2001** | | | | | | | |
| Revenues from unaffiliated customers | | | | | | | |
| Sale of gas | $ 3,180 | $ 2,027 | $ 2,833,369 | $ 1,390 | $ - | $ - | $ 2,839,966 |
| Sale of natural gas liquids | (156) | - | 421,723 | - | - | (6) | 421,561 |
| Equity hedges: | | | | | | | |
| Residue | 7,833 | 1,298 | - | - | - | - | 9,131 |
| Liquids | 2,521 | - | - | - | - | - | 2,521 |
| Gathering, processing and transportation revenue | 48,175 | - | - | 7,187 | 36 | - | 55,398 |
| Total revenues from unaffiliated | 61,553 | 3,325 | 3,255,092 | 8,577 | 36 | (6) | 3,328,577 |
| Inter-segment sales | 816,125 | 113,022 | 29,897 | 17,103 | (545) | (975,602) | - |
| Non-cash change in fair value of derivatives | (208) | 188 | 19,926 | - | - | - | 19,906 |
| Interest income | 1 | 12 | - | 1 | 13,683 | (12,860) | 836 |
| Other, net | 4,031 | 31 | 17 | - | (237) | - | 3,843 |
| Total revenues | 881,502 | 116,578 | 3,304,932 | 25,681 | 12,937 | (988,468) | 3,353,162 |
| Product purchases | 678,985 | 2,789 | 3,254,902 | - | 195 | (949,921) | 2,986,950 |
| Plant operating and transportation expense | 68,473 | 117 | - | 9,213 | (204) | (2,066) | 75,533 |
| Oil and gas exploration and production expense | - | 49,277 | - | - | - | (21,750) | 27,527 |
| Earnings from equity investments | (1,790) | - | - | - | - | - | (1,790) |
| Operating profit | 135,834 | 64,395 | 50,030 | 16,468 | 12,946 | (14,731) | 264,942 |
| | | | | | | | |
| Depreciation, depletion and amortization | 39,141 | 17,692 | 161 | 1,646 | 5,522 | - | 64,162 |
| Selling and administrative expense | 16,108 | 7,197 | 8,911 | 2,056 | - | - | 34,272 |
| Gain from sale of assets | (11,118) | (326) | - | 511 | 185 | - | (10,748) |
| Interest expense | - | - | - | - | 25,130 | - | 25,130 |
| Segment profit | $ 91,703 | $ 39,832 | $ 40,958 | $ 12,255 | $(17,891) | $ (14,731) | $ 152,126 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Identifiable assets | | | | | | | |
| Other allocated assets | $ 4,142 | $ 3,724 | $ 131,705 | $ 1,078 | $ 290,239 | $ (63,115) | $ 367,773 |
| Investment in others | 1,806 | - | - | 3,453 | 39,551 | (34,531) | 10,279 |
| Capital assets | 613,203 | 178,572 | 1,830 | 43,452 | 52,833 | - | 889,890 |
| Total identifiable assets | $ 619,151 | $ 182,296 | $ 133,535 | $ 47,983 | $ 382,623 | $ (97,646) | $ 1,267,942 |

| | Gas Gathering and Processing | Exploration and Production | Marketing | Trans- portation | Corporate | Elim- inating Entries | Total |
|---|---|---|---|---|---|---|---|
| **Year ended December 31, 2000** | | | | | | | |
| Revenues from unaffiliated customers | | | | | | | |
| Sale of gas | $ 368 | $ 39 | $ 2,659,564 | $ 1,114 | $ - | $ - | $ 2,661,085 |
| Sale of natural gas liquids | - | - | 596,793 | - | - | (9) | 596,784 |
| Equity hedges: | | | | | | | |
| Residue | (6,969) | (26,064) | - | - | - | - | (33,033) |
| Liquids | (5,852) | - | - | - | - | - | (5,852) |
| Gathering, processing and transportation revenue | 45,613 | - | - | 7,506 | 37 | - | 53,156 |
| Total revenues from unaffiliated | 33,160 | (26,025) | 3,256,357 | 8,620 | 37 | (9) | 3,272,140 |
| Inter-segment sales | 776,264 | 84,972 | 94,858 | 16,484 | 44 | (972,622) | - |
| Non-cash change in fair value of derivatives | - | - | - | - | - | - | - |
| Interest income | 98 | 6 | 27 | - | 27,505 | (26,987) | 649 |
| Other, net | 7,191 | 137 | (65) | - | - | 39 | 7,302 |
| Total revenues | 816,713 | 59,090 | 3,351,177 | 25,104 | 27,586 | (999,579) | 3,280,091 |
| Product purchases | 616,594 | 1,268 | 3,331,634 | - | (189) | (963,806) | 2,985,501 |
| Plant operating and transportation expense | 63,621 | 376 | 69 | 7,802 | (264) | (1,712) | 69,892 |
| Oil and gas exploration and production expense | - | 28,645 | - | - | - | (9,124) | 19,521 |
| Earnings from equity investments | (1,897) | - | - | - | - | - | (1,897) |
| Operating profit | 138,395 | 28,801 | 19,474 | 17,302 | 28,039 | (24,937) | 207,074 |
| Depreciation, depletion and amortization | 35,010 | 15,435 | 161 | 1,676 | 5,668 | (31) | 57,919 |
| Selling and administrative expense | 20,298 | 5,058 | 6,440 | 1,921 | - | - | 33,717 |
| Gain from sale of assets | (3,800) | (369) | 8 | - | (5,245) | - | (9,406) |
| Interest expense | - | - | - | - | 33,460 | - | 33,460 |
| Segment profit | $ 86,887 | $ 8,677 | $ 12,865 | $ 13,705 | $ (5,844) | $ (24,906) | $ 91,384 |
| Identifiable assets | | | | | | | |
| Other allocated assets | $ 30,950 | $ 4,299 | $ 113,249 | $ 1,026 | $ 492,307 | $ (9,091) | $ 632,740 |
| Investment in others | 1,176 | - | - | 4,201 | 136 | 154 | 5,667 |
| Capital assets | 571,122 | 125,853 | 1,991 | 43,110 | 50,945 | 1 | 793,022 |
| Total identifiable assets | $ 603,248 | $ 130,152 | $ 115,240 | $ 48,337 | $ 543,388 | $ (8,936) | $ 1,431,429 |

## NOTE 10 - EMPLOYEE BENEFIT PLANS

*Retirement Plan.* A discretionary retirement plan (a defined contribution plan) exists for all Company employees meeting certain service requirements. The Company may make annual discretionary contributions to the plan as determined by the board of directors and, during 2000, provided for a match of 50% of employee contributions on the first 4% of employee compensation contributed. Effective January 2001, the match of employee contributions has been increased to a sliding scale of 60% to 100% of the first 5% of employee compensation based upon years of service. Contributions are made to mutual funds and to purchase Company stock for which Fidelity Management Trust Company acts as trustee. The discretionary contributions made by the Company were $1.9 million, $2.3 million and $2.3 million, for the years ended December 31, 2002, 2001 and 2000, respectively. The matching contributions were approximately $1.3 million, $1.3 million and $470,000 for the years ended December 31, 2002, 2001 and 2000, respectively.

*Key Employees' Incentive Stock Option Plan and 1987 Non-Employee Directors Stock Option Plan.* Effective April 1987, the board of directors of the Company adopted a Key Employees' Incentive Stock Option Plan ("Key Employee Plan") and a Non-Employee Director Stock Option Plan ("1987 Directors Plan") that authorized the granting of options to purchase 250,000 and 20,000 shares of the Company's Common Stock, respectively. Each of these plans has terminated. The Company loaned to certain employees, an amount sufficient to exercise their options under these plans. The loan and accrued interest will be forgiven if the employee is continually employed by the Company and upon a resolution of the board of directors. As of December 31, 2002 and 2001, loans related to 27,500 and 75,000 shares of Common Stock totaling $295,000 and $803,000, respectively, were outstanding under these terms.

*1999 Non-Employee Directors Stock Option Plan.* Effective March 1999, the board of directors of the Company adopted a 1999 Non-Employee Directors' Stock Option Plan ("1999 Directors Plan") that authorized the granting of options to purchase 15,000 shares of the Company's Common Stock. During 1999, the board approved grants totaling 15,000 options to several board members. Under this plan, each of these options becomes exercisable as to 33 1/3% of the shares covered by it on each anniversary from the date of grant. This plan terminates on the earlier of March 12, 2009 or the date on which all options granted under the plan have been exercised in full.

*1993, 1997 and 1999 Stock Option Plans.* The 1993 Stock Option Plan ("1993 Plan"), the 1997 Stock Option Plan ("1997 Plan"), and the 1999 Stock Option Plan ("1999 Plan") became effective on March 29, 1993, May 21, 1997, and May 21, 1999, respectively, after approvals by the Company's stockholders. Each plan is intended to be an incentive stock option plan in accordance with the provisions of Section 422 of the Internal Revenue Code of 1986, as amended. The Company has reserved 1,000,000 shares of Common Stock for issuance upon exercise of options under each of the 1993 Plan and the 1997 Plan and 750,000 shares of Common Stock for issuance upon exercise of options under the 1999 Plan. The 1993 Plan, the 1997 Plan and the 1999 Plan will terminate on the earlier of March 29, 2003, May 21, 2007 and May 21, 2009, respectively, or the date on which all options granted under each of the plans have been exercised in full. Although options covering 637,818 shares remain to be granted under the 1993 and 1997 Stock Option Plans, no further options will be granted under either plan.

Effective January 1, 2001, these plans were amended to allow for the exercise of stock options granted under these plans by the surrender to the Company of previously acquired shares of the Company's common stock. This amendment allows for the constructive exchange of Company stock already owned in payment for shares to be received under the option exercise. The price for the exchanged shares is the average closing price of the Company common stock for the ten days preceding the granting of an option.

*Chief Executive Officer and President's Plan.* Pursuant to the Employment Agreement, dated October 15, 2001, and the Stock Option Agreement, dated as of November 1, 2001, between the Company and Peter A. Dea, the Company's CEO and President, non-qualified stock options were granted for the purchase of 300,000 shares of the Company's common stock. The exercise price of the options was equal to $5.00 below the closing price per share on the effective date of the Employment Agreement. The stock options are subject to the conditions of the Agreements and vest equally over four years. The difference between the closing price on the effective date and the exercise price is being amortized over four years as compensation expense.

*2002 Non-Employee Directors Stock Option Plan.* Effective May 2002, the shareholders approved the 2002 Non-Employee Directors' Stock Option Plan ("2002 Directors Plan") that authorized the granting of options to purchase 110,000 shares of the Company's Common Stock. The 2002 Directors Plan provides for a three-year vesting schedule while the non-employee director serves on our board. Under this plan, a newly elected non-employee director will be granted 5,000 options to acquire common stock as of the date of election. The 2002 Directors Plan also provides for an annual grant on the date of our annual meeting to each non-employee director of 2,000 options to acquire common stock. The purchase price of the stock under each option shall be the fair market value of the stock at the time such option is granted and no options shall be re-priced. The 2002 Directors Plan requires the non-employee director to exercise the option at the earlier of ten years from the date of the plan or within five years of the date each portion vests. The non-employee director's right to exercise options under the 2002 Directors Plan is subject to continuous service since the grant was made. If the non-employee director dies or becomes disabled (within the meaning of the 2002 Directors Plan) or a change of control occurs, then all of the options granted to the non-employee director shall become 100% exercisable. During 2002, a total of 18,000 options were granted under this plan.

*2002 Stock Option Plan.* Effective May 2002, the shareholders approved the 2002 Stock Incentive Plan ("2002 Plan") that authorized the granting of options to purchase 1,250,000 shares of the Company's common stock. No employee may be granted more than 125,000 options to acquire common stock in any fiscal year. The 2002 Plan requires the employee to exercise the option at the earlier of ten years from the date of the 2002 Plan or within five years of the date each portion vests. The employee's right to exercise options under the 2002 Plan is subject to continuous employment since the grant was made. If the employee dies, becomes disabled (within the meaning of the 2002 Plan) or a change of control occurs, then all of the options granted to the employee shall become 100% exercisable. The 2002 Plan will terminate on the earlier of May 17, 2012 or the date on which all options granted under the plan have been exercised in full. During 2002, a total of 187,997 options were granted under this plan.

Under each of the 1993, 1997, 1999 and 2002 plans, the board of directors of the Company determines and designates from time to time those employees of the Company to whom options are to be granted. If any option terminates or expires prior to being exercised, the shares relating to such option are released and may be subject to re-issuance pursuant to a new option. The board of directors has the right to, among other things, fix the method by which the price is determined and the terms and conditions for the grant or exercise of any option. The purchase price of the stock under each option shall be the average closing price for the ten days prior to the grant. Under the 1993 Plan, options granted vest 20% each year on the anniversary of the date of grant. Under the 1997, 1999 and 2002 Plans, the board of directors has the authority to set the vesting schedule from 20% per year to 33 1/3% per year. Under each of the plans, the employee must exercise the option within five years of the date each portion vests.

In March 1999, certain officers of the Company were granted a total of 300,000 options, which vest ratably over the next three years, under the 1997 Plan. The exercise price of $5.51 per share was determined by using the average stock price for the ten trading days prior to the grant date. In exchange, these officers were required to relinquish a total of 246,200 vested and unvested options at prices ranging from $18.63 to $34.00 per share.

The following table summarizes the number of stock options exercisable and available for grant under the Company's benefit plans:

| | Per Share Price Range | 1999 Directors Plan | 1993 Plan | 1997 Plan | 1999 Plan | Chief Executive Officer's Plan | 2002 Stock Incentive Plan | 2002 Non-Employee Director's Plan |
|---|---|---|---|---|---|---|---|---|
| Exercisable: | | | | | | | | |
| December 31, 2002... | $0.01–5.00 | - | - | 21,071 | - | - | - | - |
| | $5.01–10.00 | 8,350 | - | 70,334 | - | - | - | - |
| | $10.01-15.00 | - | 5,474 | 33,600 | 14,446 | - | - | - |
| | $15.01-20.00 | - | 37,806 | 34,400 | 3,036 | - | - | - |
| | $20.01-25.00 | - | 5,816 | - | 31,975 | - | - | - |
| | $25.01-30.00 | - | - | - | 1,667 | 75,000 | - | - |
| | $30.01-35.00 | - | 4,289 | - | 11,441 | - | - | - |
| | $35.01-40.00 | - | - | - | 58,800 | - | - | - |
| | TOTAL | 8,350 | 53,385 | 159,405 | 121,365 | 75,000 | - | - |
| December 31, 2001... | $0.01–5.00 | - | - | 40,350 | - | - | - | - |
| | $5.01–10.00 | 7,789 | - | 86,445 | - | - | - | - |
| | $10.01-15.00 | - | 125,201 | 50,400 | 12,223 | - | - | - |
| | $15.01-20.00 | - | 18,358 | 34,440 | 2,438 | - | - | - |
| | $20.01-25.00 | - | 52,184 | - | 24,176 | - | - | - |
| | $25.01-30.00 | - | - | - | - | - | - | - |
| | $30.01-35.00 | - | 14,377 | - | - | - | - | - |
| | $35.01-40.00 | - | - | - | - | - | - | - |
| | TOTAL | 7,789 | 210,120 | 211,635 | 38,837 | - | - | - |
| December 31, 2000... | $0.01–5.00 | - | - | 20,111 | - | - | - | - |
| | $5.01–10.00 | 1,683 | - | 32,000 | - | - | - | - |
| | $10.01- | - | 176,503 | 17,520 | 8,888 | - | - | - |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 15.00 | | | | | | | |
| $15.01-20.00 | - | 99,029 | 32,280 | 2,367 | - | - | - |
| $20.01-25.00 | - | 21,138 | - | - | - | - | - |
| $25.01-30.00 | - | 10,176 | - | - | - | - | - |
| $30.01-35.00 | - | 82,960 | - | - | - | - | - |
| $35.01-40.00 | - | - | - | - | - | - | - |
| TOTAL | 1,683 | 389,806 | 101,911 | 11,255 | - | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Available for Grant:** | | | | | | | | |
| December 31, 2002... | - | - | - | - | - | - | 1,062,003 | 92,000 |
| December 31, 2001... | - | - | - | - | 287,634 | - | - | - |
| December 31, 2000... | - | - | - | - | 608,934 | - | - | - |

The following table summarizes the stock option activity under the Company's benefit plans:

| | Per Share Price Range | 1999 Directors Plan | 1993 Plan | 1997 Plan | 1999 Plan | Chief Executive Officer's Plan | 2002 Stock Incentive Plan | 2002 Non-Employee Director's Plan |
|---|---|---|---|---|---|---|---|---|
| Balance 12/31/99 | | 15,000 | 565,874 | 646,700 | 35,266 | | | |
| Granted................ | $12.58-23.45 | - | - | - | 115,300 | - | - | - |
| Exercised.............. | $4.59-20.69 | (3,317) | (59,621) | (136,722) | (100) | - | - | - |
| Forfeited or canceled... | $4.59-35.00 | - | (38,232) | (8,601) | (9,500) | - | - | - |
| Balance 12/31/00 | | 11,683 | 468,021 | 501,377 | 140,966 | - | - | - |
| Granted................ | $25.01-36.34 | - | - | - | 413,200 | 300,000 | - | - |
| Exercised.............. | $4.59-35.00 | - | (201,940) | (150,056) | (16,740) | - | - | - |
| Forfeited or canceled... | $4.59-36.34 | - | (37,891) | (2,501) | (19,600) | - | - | - |
| Balance 12/31/01 | | 11,683 | 228,190 | 348,820 | 517,286 | 300,000 | - | - |
| Granted................ | $32.95-33.45 | - | - | - | 170,000 | - | 187,997 | 18,000 |
| Exercised.............. | $4.59-35.00 | (3,333) | (161,878) | (177,315) | (41,373) | - | - | - |
| Forfeited or canceled... | $4.59-36.34 | - | (11,285) | (12,100) | (15,070) | - | - | - |
| Balance 12/31/02 | | 8,350 | 55,027 | 159,405 | 631,383 | 300,000 | 187,997 | 18,000 |
| Weighted-average remaining contractual life (years) | | 3.9 | .3 | 3.9 | 5.3 | 6.3 | 6.8 | 6.8 |

The following table summarizes the weighted average option exercise price information under the Company's benefit plans:

| | 1999 Directors Plan | 1993 Plan | 1997 Plan | 1999 Plan | Chief Executive Officer's Plan | 2002 Stock Incentive Plan | 2002 Non-Employee Director's Plan |
|---|---|---|---|---|---|---|---|
| Balance 12/31/99................ | $ 5.51 | $ 19.54 | $ 7.72 | $ 13.58 | - | - | - |
| Granted........................... | - | - | - | 23.11 | - | - | - |
| Exercised........................ | (5.51) | (16.17) | (7.33) | (16.21) | - | - | - |
| Forfeited or canceled....... | - | (26.97) | (8.66) | (22.25) | - | - | - |
| Balance 12/31/00................ | 5.51 | 19.35 | 7.81 | 20.79 | - | - | - |
| Granted........................... | - | - | - | 34.72 | $ 25.01 | - | - |
| Exercised........................ | - | (19.55) | (7.22) | (18.30) | - | - | - |
| Forfeited or canceled....... | - | (25.50) | (4.59) | (29.76) | - | - | - |
| Balance 12/31/01................ | 5.51 | 18.15 | 8.08 | 31.61 | 25.01 | - | - |
| Granted........................... | - | - | - | 32.95 | - | $ 32.98 | $ 37.82 |
| Exercised........................ | (5.51) | (15.97) | (6.75) | (22.50) | - | - | - |
| Forfeited or canceled....... | - | (35.00) | (5.92) | (26.46) | - | - | - |
| Balance 12/31/02................ | $ 5.51 | $ 19.73 | $ 9.73 | $ 32.68 | $ 25.01 | $ 32.98 | $ 37.82 |

## NOTE 11 - SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED):

*Costs.* The following tables set forth capitalized costs at December 31, 2002, 2001 and 2000 and costs incurred for oil and gas producing activities for the years ended December 31, 2002, 2001 and 2000 (000s):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Capitalized costs: | | | |
| Proved properties | $ 239,579 | $ 194,596 | $ 119,124 |
| Unproved properties | 64,451 | 40,137 | 46,890 |
| Total | 304,030 | 234,733 | 166,014 |
| Less accumulated depreciation and depletion | (79,050) | (53,359) | (36,367) |
| Net capitalized costs | $ 224,980 | $ 181,374 | $ 129,647 |
| Costs incurred: | | | |
| Acquisition of properties | | | |
| Proved | $ 426 | $ 1,624 | $ 1,571 |
| Unproved | 2,770 | 5,332 | 7,203 |
| Development costs | 48,648 | 63,263 | 35,807 |
| Exploration costs | 22,547 | 2,141 | 8,397 |
| Total costs incurred | $ 74,391 | $ 72,360 | $ 52,978 |

*Results of Operations.* The results of operations for oil and gas producing activities, excluding corporate overhead and interest costs, for the years ended December 31, 2002, 2001 and 2000 are as follows (000s):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Revenues from sale of oil and gas: | | | |
| Sales | $ 2,227 | $ 4,517 | $ 4,658 |
| Transfers | 112,137 | 110,532 | 80,353 |
| Total | 114,364 | 115,049 | 85,011 |
| Production costs | (65,536) | (49,421) | (27,108) |
| Exploration costs | (3,543) | (3,234) | (2,213) |
| Depreciation, depletion and amortization | (25,691) | (17,175) | (13,423) |
| Income tax expense | (7,558) | (15,827) | (14,793) |
| Results of operations | $ 12,036 | $ 29,392 | $ 27,474 |

*Reserve Quantity Information.* Reserve estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and of future net cash flows expected therefrom prepared by different engineers or by the same engineers at different times may vary substantially. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in commodity prices and operating costs. Any significant revision of reserve estimates could materially adversely affect the Company's financial condition and results of operations.

The following table sets forth information for the years ended December 31, 2002, 2001 and 2000 with respect to changes in the Company's proved developed and undeveloped reserves, all of which are in the United States.

| | Natural Gas (MMcf) | Crude Oil (MBbls) |
|---|---|---|
| Proved reserves: | | |
| December 31, 1999 | 271,818 | 329 |
| Revisions of previous estimates | (11,889) | (194) |
| Extensions and discoveries | 176,584 | 332 |
| (Sales) Purchases of reserves in place | - | - |
| Production | (28,019) | (28) |
| December 31, 2000 | 408,494 | 439 |
| Revisions of previous estimates | (18,415) | (110) |
| Extensions and discoveries | 115,672 | 377 |
| (Sales) Purchases of reserves in place | - | - |
| Production | (35,514) | (45) |
| December 31, 2001 | 470,237 | 661 |
| Revisions of previous estimates | (88,371) | 105 |
| Extensions and discoveries | 246,700 | 500 |
| (Sales) Purchases of reserves in place | (500) | - |
| Production | (47,401) | (53) |
| December 31, 2002 | 580,665 | 1,213 |
| Proved developed reserves, included above: | | |
| December 31, 1999 | 106,626 | 161 |
| December 31, 2000 | 208,218 | 147 |
| December 31, 2001 | 252,266 | 262 |
| December 31, 2002 | 265,300 | 400 |

***Standardized Measures of Discounted Future Net Cash Flows.*** Estimated discounted future net cash flows and changes therein were determined in accordance with SFAS No. 69, "Disclosures about Oil and Gas Producing Activities." Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes such information is essential for a proper understanding and assessment of the data presented.

Future cash inflows are computed by applying year-end prices of oil and gas relating to the Company's proved reserves to the year-end quantities of those reserves.

The assumptions used to compute estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, or their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the Company's proved oil and gas reserves. Permanent differences in oil and gas related tax credits and allowances are recognized.

An annual discount rate of 10% was used to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

Information with respect to the Company's estimated discounted future cash flows from its oil and gas properties for the years ended December 31, 2002, 2001 and 1999 is as follows (000s):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| Future cash inflows | $ 1,587,891 | $ 691,188 | $ 2,682,435 |
| Future production costs | (463,471) | (210,242) | (462,065) |
| Future development costs | (193,255) | (110,365) | (87,251) |
| Future income tax expense | (305,263) | (108,270) | (732,327) |
| Future net cash flows | 625,902 | 262,311 | 1,400,792 |
| 10% annual discount for estimated timing of cash flows | (265,250) | (90,941) | (432,881) |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves | $ 360,652 | $ 171,370 | $ 967,911 |

Principal changes in the Company's estimated discounted future net cash flows for the years ended December 31, 2002, 2001 and 2000 are as follows (000s):

| | 2002 | 2001 | 2000 |
|---|---|---|---|
| January 1 | $ 171,370 | $ 967,911 | $ 112,927 |
| Sales and transfers of oil and gas produced, net of production costs | (50,828) | (65,628) | (57,903) |
| Net changes in prices and production costs related to future production | 263,448 | (1,349,674) | 768,840 |
| Development costs incurred during the period | 40,753 | 50,494 | 35,807 |
| Changes in estimated future development costs | (42,869) | (37,115) | (21,369) |
| Changes in extensions and discoveries | 148,114 | 57,300 | 640,501 |
| Revisions of previous quantity estimates | (87,705) | (34,596) | (64,710) |
| Purchases (sales) of reserves in place | (586) | - | - |
| Accretion of discount | 24,118 | 147,393 | 15,706 |
| Net change in income taxes | (105,163) | 435,285 | (461,888) |
| December 31 | $ 360,652 | $ 171,370 | $ 967,911 |

## NOTE 12 - QUARTERLY RESULTS OF OPERATIONS (UNAUDITED):

The following summarizes certain quarterly results of operations (000s, except per share amounts):

| | Operating Revenues | Gross Profit (a) | Net Income | Earnings Per Share of Common Stock | Earnings Per Share of Common Stock - Assuming Dilution |
|---|---|---|---|---|---|
| 2002 quarter ended: | | | | | |
| March 31 | $ 615,915 | $ 27,954 | $ 8,000 | $ .18 | $ .18 |
| June 30 | 614,122 | 40,466 | 13,766 | .35 | .34 |
| September 30 | 614,089 | 38,122 | 13,387 | .34 | .34 |
| December 31 | 645,572 | 37,888 | 15,436 | .38 | .37 |
| | $ 2,489,698 | $ 144,430 | $ 50,589 | $ 1.25 | $ 1.23 |
| 2001 quarter ended: | | | | | |
| March 31 | $ 1,196,834 | $ 69,556 | $ 40,590 | $ 1.17 | $ 1.08 |
| June 30 | 886,672 | 59,853 | 29,453 | .82 | .77 |
| September 30 | 670,521 | 37,687 | 14,773 | .37 | .36 |
| December 31 | 599,135 | 33,684 | 10,821 | .23 | .22 |
| | $ 3,353,162 | $ 200,780 | $ 95,637 | $ 2.59 | $ 2.48 (b) |

(a) Excludes selling and administrative, interest and income tax expenses, (gains) or losses on sale of assets, and extraordinary charges for early extinguishment of debt.

(b) The sum of the quarterly calculations of earnings per share of common stock – assuming dilution do not total to the annual amount due to the inclusion of differing common stock equivalents in the various quarters and in the year as a whole.

## NOTE 13 – GUARANTOR AND NON-GUARANTOR SUBSIDIARIES:

The Company's payment obligations under its Revolving Credit Facility, its Master Shelf Agreement and its Senior Subordinated Notes (collectively the "Financing Facilities") are fully and unconditionally guaranteed by its significant subsidiaries to the extent allowed by applicable law. These guarantees are joint and several and in the case of the Senior Subordinated Notes, are subordinated in right of payment to senior debt of the guarantors.

During the years ended December 31, 2002 and 2001, the guarantors of the Company's payment obligations under its financing facilities were Lance Oil & Gas Company, Inc., Western Gas Resources-Texas, Inc., Mountain Gas Resources, Inc., MIGC, Inc., MGTC, Inc. and Western Gas Wyoming, L.L.C., (collectively, the "Guarantor Subsidiaries"). During the year ended December 31, 2000, in addition to the Guarantor Subsidiaries, Pinnacle Gas Treating, Inc. and Western Gas Resources-Oklahoma, Inc. were also guarantors.

The Company's subsidiaries that did not guarantee the Company's payment obligations under its financing facilities during the years ended December 31, 2002, 2001 and 2000 included Western Power Services, Inc., Western Gas Resources-Westana, Inc. and WGR Canada, Inc. (collectively, the "Non-Guarantor Subsidiaries").

Presented below is condensed consolidating financial information for Western Gas Resources, Inc. (the "Parent Company"), the Guarantor Subsidiaries and the Non-Guarantor Subsidiaries. Balance sheet data are presented as of December 31, 2002 and 2001. The Statement of Operations and Statement of Cash Flows data are presented for the years ended December 31, 2002, 2001 and 2000.

For purposes of the following tables, the Parent Company's investments in its subsidiaries are accounted for using the equity method of accounting. Net income of Guarantor and Non-Guarantor Subsidiaries is, therefore, reflected in the Parent Company column under Earnings from equity investments. Selling and administrative expense and Provision for income taxes are primarily reflected in the Parent Company column. The Consolidating Entries eliminate the investments in the subsidiaries and other inter-company transactions for consolidated reporting purposes.

## Supplemental Condensed Consolidating Balance Sheet
## As of December 31, 2002

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Entries | TOTAL |
|---|---|---|---|---|---|
| ASSETS | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | 7,138 | 128 | 46 | - | 7,312 |
| Trade accounts receivable, net | 256,508 | 14,013 | 10,382 | (27,316) | 253,587 |
| Inventory | 36,406 | - | 7,076 | - | 43,482 |
| Assets held for sale | 3,250 | - | - | - | 3,250 |
| Assets from price risk management activities | 34,873 | - | - | - | 34,873 |
| Other | 29,847 | (2,675) | 572 | - | 27,744 |
| Total current assets | 368,022 | 11,466 | 18,076 | (27,316) | 370,248 |
| Total property and equipment, net | 348,937 | 466,538 | 51,271 | (100) | 866,646 |
| Other assets: | | | | | |
| Gas purchase contracts, net | 7,722 | 23,202 | - | - | 30,924 |
| Assets from price risk management activities | 406 | - | - | - | 406 |
| Other assets | 58,864 | 486 | 5 | (51,051) | 8,304 |
| Investments in subsidiaries | 444,823 | 22,777 | 2,839 | (444,823) | 25,616 |
| Total other assets | 511,815 | 46,465 | 2,844 | (495,874) | 65,250 |
| Total assets | 1,228,774 | 524,469 | 72,191 | (523,290) | 1,302,144 |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | | | |
| Current liabilities: | | | | | |
| Accounts payable | 211,220 | 45,003 | 15,078 | (28,314) | 242,987 |
| Accrued expenses | 40,091 | 9,472 | 1,946 | - | 51,509 |
| Liabilities from price risk management activities | 34,811 | - | - | - | 34,811 |
| Dividends payable | 3,464 | - | - | - | 3,464 |
| Total current liabilities | 289,586 | 54,475 | 17,024 | (28,314) | 332,771 |
| Long-term debt | 359,933 | - | - | - | 359,933 |
| Other long-term liabilities | 1,713 | 44,967 | 6,084 | (51,051) | 1,713 |
| Liabilities from price risk management activities | 406 | - | - | - | 406 |
| Deferred income taxes payable | 99,642 | 29,287 | - | (4,676) | 124,253 |
| Total liabilities | 751,280 | 128,729 | 23,108 | (84,041) | 819,076 |
| Total stockholders' equity | 477,494 | 395,740 | 49,083 | (439,249) | 483,068 |
| Total liabilities and stockholders' equity | 1,228,774 | 524,469 | 72,191 | (523,290) | 1,302,144 |

## Supplemental Condensed Consolidating Statement of Operations
## For the year ended December 31, 2002

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Entries | TOTAL |
|---|---|---|---|---|---|
| Total revenues | 2,943,035 | 213,484 | 130,457 | (797,278) | 2,489,698 |
| Costs and expenses: | | | | | |
| Product purchases | 2,758,546 | 39,773 | 118,164 | (759,304) | 2,157,179 |
| Plant operating expense | 54,703 | 25,968 | 2,834 | (1,975) | 81,530 |
| Oil and gas exploration and production costs | 1,290 | 61,859 | - | (29,142) | 34,007 |
| Depreciation, depletion and amortization | 31,323 | 42,739 | 2,943 | - | 35,828 |
| Selling and administrative expense | 33,066 | 2,562 | 254 | (54) | 77,005 |
| (Gain) loss on sale of assets | 1,095 | 157 | 272 | (576) | 948 |
| Earnings from equity investments | (41,206) | (2,259) | (2,194) | 41,206 | (4,453) |
| Interest expense | 26,883 | 8,548 | 132 | (8,612) | 26,951 |

| | | | | | |
|---|---|---|---|---|---|
| Total costs and expenses | 2,865,700 | 179,347 | 122,405 | (799,663) | 2,408,995 |
| Income before income taxes | 77,335 | 34,137 | 8,052 | 38,821 | 80,703 |
| Total provision for income taxes | 29,131 | - | 983 | - | 30,114 |
| Net income | 48,204 | 34,137 | 7,069 | (38,821) | 50,589 |

**Supplemental Condensed Consolidating Statement of Cash Flows**
**For the year ended December 31, 2002**

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Entries | TOTAL |
|---|---|---|---|---|---|
| Net cash provided by operating activities | $ 24,124 | $ 96,812 | $ 10,199 | $ 1 | $ 131,136 |
| Cash flows from investing activities: | | | | | |
| Purchases of property and equipment, including acquisitions | (36,516) | (84,018) | (7,525) | 2,459 | (125,600) |
| Proceeds from the disposition of property and equipment | 33,060 | 4,189 | 75 | (2,459) | 34,865 |
| Other net cash used in investing activities | 5,195 | (15,022) | (5,209) | (1) | (15,037) |
| Net cash used in investing activities | 1,739 | (94,851) | (12,659) | (1) | (105,722) |
| Cash flows from financing activities: | | | | | |
| Payments on revolving credit facility | (992,945) | - | - | - | (992,945) |
| Borrowings under revolving credit facility | 994,545 | - | - | - | 994,545 |
| Dividends paid | (15,107) | - | - | - | (15,107) |
| Other net cash used in financing activities | (14,577) | - | - | - | (14,577) |
| Net cash used in financing activities | (28,084) | - | - | - | (28,084) |
| Net decrease in cash and cash equivalents | (2,221) | 1,961 | (2,460) | - | (2,720) |
| Cash and cash equivalents at beginning of year | 9,359 | (1,833) | 2,506 | - | 10,032 |
| Cash and cash equivalents at end of year | $ 7,138 | $ 128 | $ 46 | $ - | $ 7,312 |

**Supplemental Condensed Consolidating Balance Sheet**
**As of December 31, 2001**

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Entries | TOTAL |
|---|---|---|---|---|---|
| ASSETS | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | 9,359 | (1,833) | 2,506 | - | 10,032 |
| Trade accounts receivable, net | 227,738 | 9,550 | 15,039 | (31,790) | 220,537 |
| Inventory | 42,194 | - | 8,579 | - | 50,773 |
| Assets held for sale | - | - | - | - | - |
| Assets from price risk management activities | 66,271 | - | - | - | 66,271 |
| Other | 15,246 | 2,865 | 239 | - | 18,350 |
| Total current assets | 360,808 | 10,582 | 26,363 | (31,790) | 365,963 |
| Total property and equipment, net | 376,005 | 427,936 | 47,036 | (2,670) | 848,307 |
| Other assets: | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Gas purchase contracts, net | 8,156 | 24,670 | - | - | 32,826 |
| Assets from price risk management activities | 2,934 | - | - | - | 2,934 |
| Other assets | 66,845 | 781 | 3 | (56,833) | 10,796 |
| Investment in subsidiaries | 404,215 | 5,496 | 1,620 | (404,215) | 7,116 |
| Total other assets | 482,150 | 30,947 | 1,623 | (461,048) | 53,672 |
| Total assets | 1,218,963 | 469,465 | 75,022 | (495,508) | 1,267,942 |
| LIABILITIES AND STOCKHOLDERS' EQUITY | | | | | |
| Current liabilities: | | | | | |
| Accounts payable | 230,928 | 29,686 | 19,200 | (19,606) | 260,208 |
| Accrued expenses | 17,857 | 3,923 | 1,343 | - | 23,123 |
| Liabilities from price risk management activities | 18,075 | - | - | - | 18,075 |
| Dividends payable | 3,767 | - | - | - | 3,767 |
| Total current liabilities | 270,627 | 33,609 | 20,543 | (19,606) | 305,173 |
| Long-term debt | 366,667 | - | - | - | 366,667 |
| Other long-term liabilities | 2,284 | 44,967 | 11,866 | (56,833) | 2,284 |
| Liabilities from price risk management activities | 1,720 | - | - | - | 1,720 |
| Deferred income taxes payable | 94,135 | 29,287 | - | (4,676) | 118,746 |
| Total liabilities | 735,433 | 107,863 | 32,409 | (81,115) | 794,590 |
| Total stockholders' equity | 483,530 | 361,602 | 42,613 | (414,393) | 473,352 |
| Total liabilities and stockholders' equity | 1,218,963 | 469,465 | 75,022 | (495,508) | 1,267,942 |

## Supplemental Condensed Consolidating Statement of Operations
## For the year ended December 31, 2001

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Entries | TOTAL |
|---|---|---|---|---|---|
| Total revenues | 3,909,286 | 238,063 | 192,463 | (986,650) | 3,353,162 |
| Costs and expenses: | | | | | |
| Product purchases | 3,687,109 | 62,101 | 186,476 | (948,736) | 2,986,950 |
| Plant operating expense | 52,033 | 23,932 | 2,819 | (3,251) | 75,533 |
| Oil and gas exploration and production costs | 793 | 48,484 | - | (21,750) | 27,527 |
| Depreciation, depletion and amortization | 31,051 | 31,150 | 1,930 | 31 | 64,162 |
| Selling and administrative expense | 27,676 | 6,356 | 293 | (53) | 34,272 |
| (Gain) loss on sale of assets | 226 | (10,974) | - | - | (10,748) |
| Earnings from equity investments | (62,747) | (185) | (1,605) | 62,747 | (1,790) |
| Interest expense | 21,750 | 14,054 | 488 | (11,162) | 25,130 |
| Total costs and expenses | 3,757,891 | 174,918 | 190,401 | (922,174) | 3,201,036 |
| Income before income taxes | 151,395 | 63,145 | 2,062 | (64,476) | 152,126 |
| Total provision for income taxes | 56,489 | 2,460 | - | (2,460) | 56,489 |
| Net income | 94,906 | 60,685 | 2,062 | (62,016) | 95,637 |

**Supplemental Condensed Consolidating Statement of Cash Flows**
**For the year ended December 31, 2001**

| | Parent Company | Guarantor Subsidiaries | Guarantor Subsidiaries | Non-Consolidating Entries | TOTAL |
|---|---|---|---|---|---|
| Net cash provided by operating activities | $ 59,505 | $ 77,899 | $ 16,327 | $ (464) | $ 153,267 |
| Cash flows from investing activities: | | | | | |
| Purchases of property and equipment, including acquisitions | (38,174) | (111,314) | (14,489) | - | (163,977) |
| Proceeds from the disposition of property and equipment | 75 | 38,019 | - | - | 38,094 |
| Other net cash used in investing activities | (1,240) | (5,310) | 312 | 464 | (5,774) |
| Net cash used in investing activities | (39,339) | (78,605) | (14,177) | 464 | (131,657) |
| Cash flows from financing activities: | | | | | |
| Payments on revolving credit facility | (528,330) | - | - | - | (528,330) |
| Borrowings under revolving credit facility | 569,630 | - | - | - | 569,630 |
| Dividends paid | (16,846) | - | - | - | (16,846) |
| Other net cash used in financing activities | (48,959) | - | - | - | (48,959) |
| Net cash used in financing activities | (24,505) | - | - | - | (24,505) |
| Net decrease in cash and cash equivalents | (4,339) | (706) | 2,150 | - | (2,895) |
| Cash and cash equivalents at beginning of year | 13,698 | (1,127) | 356 | - | 12,927 |
| Cash and cash equivalents at end of year | $ 9,359 | $ (1,833) | $ 2,506 | $ - | $ 10,032 |

**Supplemental Condensed Consolidating Statement of Operations**
**For the year ended December 31, 2000**

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Entries | TOTAL |
|---|---|---|---|---|---|
| Total revenues | 3,882,985 | 286,899 | 161,031 | (1,050,824) | 3,280,091 |
| Costs and expenses: | | | | | |
| Product purchases | 3,723,729 | 125,464 | 148,522 | (1,012,214) | 2,985,501 |
| Plant operating expense | 43,031 | 27,393 | 2,561 | (3,093) | 69,892 |
| Oil and gas exploration and production costs | 1,982 | 26,662 | - | (9,123) | 19,521 |
| Depreciation, depletion and amortization | 28,845 | 27,308 | 1,797 | (31) | 57,919 |
| Selling and administrative expense | 29,958 | 3,390 | 423 | (54) | 33,717 |
| (Gain) loss on sale of assets | (9,085) | (321) | - | - | (9,406) |
| Earnings from equity investments | (60,560) | - | (1,897) | 60,560 | (1,897) |
| Interest expense | 33,381 | 26,281 | 557 | (26,759) | 33,460 |
| Total costs and expenses | 3,791,281 | 236,177 | 151,963 | (990,714) | 3,188,707 |
| Income before income taxes | 91,704 | 50,722 | 9,068 | (60,110) | 91,384 |
| Total provision for income taxes | 33,501 | (831) | 61 | 831 | 33,562 |
| Net income | 58,203 | 51,553 | 9,007 | (60,941) | 57,822 |

**Supplemental Condensed Consolidating Statement of Cash Flows**
**For the year ended December 31, 2000**

| | Parent Company | Guarantor Subsidiaries | Non-Guarantor Subsidiaries | Consolidating Entries | TOTAL |
|---|---|---|---|---|---|
| Net cash provided by operating activities | $ 80,522 | $ 48,672 | $ (12,555) | $ (377) | $ 116,262 |
| Cash flows from investing activities: | | | | | |
| Purchases of property and equipment, including acquisitions | (41,837) | (59,238) | (7,492) | 31 | (108,536) |
| Proceeds from the disposition of property and equipment | 18,046 | 8,438 | - | - | 26,484 |
| Other net cash used in investing activities | (7,882) | - | 7,549 | 346 | 13 |
| Net cash used in investing activities | (31,673) | (50,800) | 57 | 377 | (82,039) |
| Cash flows from financing activities: | | | | | |
| Payments on revolving credit facility | (1,392,286) | - | - | - | (1,392,286) |
| Borrowings under revolving credit facility | 1,399,736 | - | - | - | 1,399,736 |
| Dividends paid | (16,877) | - | - | - | (16,877) |
| Other net cash used in financing activities | (25,931) | - | - | - | (25,931) |
| Net cash used in financing activities | (35,358) | - | - | - | (35,358) |
| Net decrease in cash and cash equivalents | 13,491 | (2,128) | (12,498) | - | (1,135) |
| Cash and cash equivalents at beginning of year | 207 | 1,001 | 12,854 | - | 14,062 |
| Cash and cash equivalents at end of year | $ 13,698 | $ (1,127) | $ 356 | $ - | $ 12,927 |

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

# PART III

## ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

## ITEM 11. EXECUTIVE COMPENSATION

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Pursuant to instruction G(3) to Form 10-K, Items 10, 11, 12 and 13 are omitted because the Company will file a definitive proxy statement (the "Proxy Statement") pursuant to Regulation 14A under the Securities Exchange Act of 1934 not later than 120 days after the close of the fiscal year. The information required by such Items will be included in the Proxy Statement to be so filed for the Company's annual meeting of stockholders scheduled for May 16, 2003 and is hereby incorporated by reference.

## ITEM 14. CONTROLS AND PROCEDURES

Under the direction of the Chief Executive Officer and President and the Executive Vice President - Chief Financial Officer, we have reviewed and evaluated our disclosure controls and procedures and believe, as of the date of management's evaluation, that our disclosure controls and procedures are reasonably designed to be effective for the purposes for which they are intended. The review and evaluation was performed within 90 days prior to the filing of this report.

There have not been any significant changes in our internal controls or any other factors that could significantly affect these controls subsequent to the date of management's evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

## ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

(1) Financial Statements:

Reference is made to page 41 for a list of all financial statements filed as a part of this report.

(2) Financial Statement Schedules:

None required.

(3) Exhibits:

3.1 Certificate of Incorporation of Western Gas Resources, Inc. (Filed as exhibit 3.1 to Western Gas Resources, Inc.'s Registration Statement on Form S-1, Registration No. 33-31604 and incorporated herein by reference).

3.2 Certificate of Amendment to the Certificate of Incorporation of Western Gas Resources, Inc. (Filed as exhibit 3.2 to Western Gas Resources, Inc.'s Registration Statement on Form S-1, Registration No. 33-31604 and incorporated herein by reference).

3.3 Amended and Restated Bylaws of Western Gas Resources, Inc. adopted by the Board of Directors on February 12, 1999. (Filed as exhibit 12.1 to Western Gas Resources, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 1999 and incorporated herein by reference).

3.4 Amended and Restated Bylaws of Western Gas Resources, Inc., adopted by the Board of Directors on October 12, 2001 (Filed as exhibit 3.3 to Western Gas Resources, Inc., 10-Q dated September 30, 2001 and incorporated herein by reference).

4.1 Western Gas Resources, Inc. Key Employees' Incentive Stock Option Plan. (Filed as exhibit 10.13 to Western Gas Resources, Inc.'s Registration Statement on Form S-4, Registration No. 33-39588 dated March 27, 1991 and incorporated herein by reference).

4.2 Certificate of Designation of 7.25% Cumulative Senior Perpetual Convertible Preferred Stock of the Company. (Filed as exhibit 3.5 to Western Gas Resources, Inc.'s Registration Statement on Form S-1, Registration No. 33-43077 dated November 14, 1991 and incorporated herein by reference).

4.3 Certificate of Designation of $2.28 Cumulative Preferred Stock of the Company. (Filed as exhibit 3.6 to Western Gas Resources, Inc.'s Registration Statement of Form S-1, Registration No. 33-53786 dated November 12, 1992 and incorporated herein by reference).

4.4 Second Amendment and First Restatement of Western Gas Processors, Ltd. Employees' Common Units Option Plan. (Filed as exhibit 10.6 to Western Gas Resources, Inc.'s Registration Statement on Form S-1, Registration No. 33-43077 dated November 14, 1991 and incorporated herein by reference).

4.5 Certificate of Designation of the $2.625 Cumulative Convertible Preferred Stock of the Company. (Filed under cover of Form 8-K dated February 24, 1994 and incorporated herein by reference).

4.6 Indenture between Western Gas Resources, Inc. and Guarantors to Chase Bank of Texas, National Association, Trustee for $225,000,000 Senior Subordinated Notes Due 2009, dated June 15, 1999. (Filed as exhibit 28 to Western Gas Resources, Inc.'s Form 10-Q for the three months ended June 30, 1999 and incorporated herein by reference).

4.7 Rights Agreement, dated as of March 22, 2001 between Western Gas Resources, Inc., and Fleet National Bank as Rights Agent, including exhibits thereto (Filed as an exhibit to Form 8-A dated March 29, 2001 and incorporated herein by reference).

4.8 Western Gas Resources, Inc., 1999 Stock Option Plan. (Filed as an exhibit to Western Gas Resources Inc.'s Registration Statement on Form S-8, Registration No. 33-95255 dated January 24, 2000 and incorporated herein by reference).

4.9 Western Gas Resources, Inc., Non-Employee Director Stock Option Plan. (Filed as an exhibit to Western Gas Resources Inc.'s Registration Statement on Form S-8, Registration No. 33-95259 dated January 24, 2000 and incorporated herein by reference).

4.10 Post Effective Amendment No. 1 to Form S-8 Registration Statement under 1999 Stock Option Plan for shares issued to certain employees dated May 23, 2001 and incorporated herein by reference.

4.11 Stock Option Plan filed for Peter A. Dea on Form S-8 Registration Statement dated December 21, 2001, and incorporated herein by reference.

4.12 Western Gas Resources, Inc., Retirement Plan registering 1,000,000 shares of common stock on Form S-8 Registration Statement dated August 14, 2002 , and incorporated herein by reference

4.13 Western Gas Resources, Inc., 2002 Stock Incentive Plan registering 1,250,000 shares of common stock on Form S-8 Registration Statement dated March 7, 2003, and incorporated herein by reference.

4.14 Western Gas Resources, Inc., 2002 Non –Employee Directors' Stock Option Plan registering 110,000 shares of common stock on Form S-8 Registration Statement dated March 7, 2003, and incorporated herein by reference.

4.15 Western Gas Resources, Inc., Exchange Offer. (Filed as an exhibit to Western Gas Resources Inc.'s Registration Statement on Form S-4, Registration No. 33-86881 dated September 10, 1999 and incorporated herein by reference).

4.16 Western Gas Resources, Inc. First Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated October 19, 1999. (Filed as exhibit 4.10 to Western Gas Resources, Inc., 10-K for the year ended 12/31/01 and incorporated herein by reference).

4.17 Western Gas Resources, Inc. Second Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated September 29, 2000. (Filed as exhibit 4.11 to Western Gas Resources, Inc., 10-K for the year ended 12/31/01 and incorporated herein by reference).

4.18 Western Gas Resources, Inc. Third Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated January 3, 2001. (Filed as exhibit 4.12 to Western Gas Resources, Inc., 10-K for the year ended 12/31/01 and incorporated herein by reference).

10.1 Restated Profit-Sharing Plan and Trust Agreement of Western Gas Resources, Inc. (Filed as exhibit 10.8 to Western Gas Resources, Inc.'s Registration Statement on Form S-4, Registration No. 33-39588 dated March 27, 1991 and incorporated herein by reference).

10.2 Registration Rights Agreement among Western Gas Resources, Inc., WGP, Inc., Heetco, Inc., NV, Dean Phillips, Inc., Sauvage Gas Company and Sauvage Gas Service, Inc. (Filed as exhibit 10.14 to Western Gas Resources, Inc.'s Registration Statement on Form S-4, Registration No. 33-39588 dated March 27, 1991 and incorporated herein by reference).

10.3 Amendment No. 1 to Registration Rights Agreement as of May 1, 1991 between Western Gas Resources, Inc., Bill Sanderson, WGP, Inc., Dean Phillips, Inc., Heetco, Inc., NV, Sauvage Gas Company and Sauvage Gas Service, Inc. (Filed as exhibit 4.2 to Western Gas Resources, Inc.'s Form 10-Q for the quarter ended June 30, 1991 and incorporated herein by reference).

10.4 Agreement to provide loans to exercise key employees' common stock options. (Filed as exhibit 10.26 to Western Gas Resources, Inc.'s Annual Report on Form 10-K for the fiscal year ended December 31, 1991 and incorporated herein by reference).

10.5 Form of revised Employment Agreement with exhibit thereto by and between Western Gas Resources, Inc., and its Executive Officers dated June 14, 2001 (Filed as exhibit 10.7 to Western Gas Resources, Inc., 10-Q dated June 30, 2001 and 10-Q dated September 30, 2001 and incorporated herein by reference).

10.6 Second Amended and Restated Master Shelf Agreement effective January 31, 1996 by and between Western Gas Resources, Inc. and Prudential Company of America. (Filed as exhibit 10.49 to Western Gas Resources, Inc.'s Form 10-K for the year ended December 31, 1995 and incorporated herein by reference).

10.7 Amended and Restated Note Purchase Agreement dated April 28, 1999 by and among Western Gas Resources, Inc. and the Purchasers identified therein. (Filed as exhibit 10.21 to Western Gas Resources, Inc.'s Form 10-Q for the three months ended March 31, 1999 and incorporated herein by reference).

10.8 Offer to Acquire Notes dated February 12, 1999 by and between Western Gas Resources, Inc. and CIGNA Investments, Inc., Royal Maccabees Life Insurance Company, The Canada Life Assurance Company, and Canada Life Insurance Company of America, original Purchasers under the Note Purchase Agreement dated as of April 1, 1993 by and between Company and Purchasers for $50,000,000, 7.65% Senior Notes due April 30, 2003. (Filed as exhibit 12.3 in Western Gas Resources, Inc. Form 10-K for the year ended December 31, 1998 and incorporated herein by reference).

10.9 Offer to Acquire Notes dated February 12, 1999 by and between Western Gas Resources, Inc. and MONY Life Insurance Company, one of the original Purchasers under the Note Purchase Agreement dated as of November 29, 1995 by and between Company and Purchasers for $42,000,000, 8.02% Senior Notes due December 1, 2005. (Filed as exhibit 12.4 in Western Gas Resources, Inc. Form 10-K for the year ended December 31, 1998 and incorporated herein by reference).

10.10 Letter Amendment No. 2 dated March 31, 1999 to the Second Amended and Restated Master Shelf Agreement effective January 31, 1996 by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America and Pruco Life Insurance Company. (Filed as exhibit 10.22 in Western Gas Resources, Inc. Form 10-Q for the three months ended March 31, 1999 and incorporated herein by reference).

10.11 Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc. and NationsBank, as agent, and the Lenders. (Filed as exhibit 10.20 in Western Gas Resources, Inc. Form 10-Q for the three months ended March 31, 1999 and incorporated herein by reference).

10.12 Letter Amendment No. 3 dated June 1, 1999 to the Second Amended and Restated Master Shelf Agreement effective January 31, 1996 by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America and Pruco Life Insurance Company. (Filed as exhibit 10.14 to Western Gas Resources, Inc., 10-K for the year ended December 31, 2000 and incorporated herein by reference.)

10.13 First Amendment dated June 10, 1999 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc. and NationsBank as Agent, and the Lenders. (Filed as exhibit 10.16 to Western Gas Resources, Inc., 10-K for the year ended 12/31/01 and incorporated herein by reference).

10.14 Third Amendment dated April 27, 2000 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc. and NationsBank, as agent, and the Lenders. (Filed as exhibit 10.23 in Western Gas Resources, Inc. Form 10-Q for the three months ended March 31, 2000 and incorporated herein by reference).

10.15 Limited Waiver, Consent, Release and Amendment No. 4 dated August 25, 2000 to the Second Amended and Restated Master Shelf Agreement effective January 31, 1996 by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America and Pruco Life Insurance Company. (Filed as exhibit 10.24 to Western Gas Resources, Inc., Form 10-Q for the nine months ended September 30, 2000 and is incorporated herein by reference).

10.16 Letter Amendment No. 5 dated March 30, 2001 to Second Amended and Restated Master Shelf Agreement dated December 19, 1991 by and between Western Gas Resources, Inc., and The Prudential Insurance Company of America. (Filed as exhibit 10.25 to Western Gas Resources, Inc., 10-Q dated March 31, 2001 and incorporated herein by reference).

10.17 Fourth Amendment dated August 25, 2000 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc. and NationsBank, as Agent, and the Lenders. (Filed as exhibit 10.25 to Western Gas Resources, Inc., Form 10-Q for the nine months ended September 30, 2000 and is incorporated herein by reference).

10.18 Fifth Amendment dated November 22, 2000 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc. and NationsBank, as agent, and the Lenders. (Filed as exhibit 10.20 to Western Gas Resources, Inc., 10-K for the year ended 12/31/01 and incorporated herein by reference).

10.19 Sixth Amendment dated April 26, 2001 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc., and NationsBank, as agent, and the Lenders. (Filed as exhibit 10.24 to Western Gas Resources, Inc., 10-Q dated March 31, 2001 and incorporated herein by reference).

10.20 Limited Waiver, Consent, Release and Amendment No. 5 dated November 22, 2000 to the Second Amended and Restated Master Shelf Agreement by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America and Pruco Life Insurance Company. (Filed as exhibit 10.21 to Western Gas Resources, Inc., 10-K for the year ended 12/31/01 and incorporated herein by reference).

10.21 Intercreditor Agreement dated April 26, 2001 by and among Western Gas Resources, Inc., Bank of America, N. A., and The Prudential Insurance Company of America. (Filed as exhibit 10.26 to Western Gas Resources, Inc., 10-Q dated March 31, 2001 and incorporated herein by reference).

10.22 Amendment to Employment Agreement by and between Western Gas Resources, Inc., and Lanny F. Outlaw, its Chief Executive Officer and President dated May 18, 2001. (Filed as exhibit 10.27 to Western Gas Resources, Inc., 10-Q dated June 30, 2001 and incorporated herein by reference).

10.23 Consultation Agreement by and between Western Gas Resources, Inc., and Lanny F. Outlaw, its Chief Executive Officer and President dated November 1, 2001. (Filed as exhibit 10.27 to Western Gas Resources, Inc., 10-Q dated June 30, 2001 and incorporated herein by reference).

10.24 Employment Agreement, as amended, dated October 15, 2001, Indemnification Agreement and Stock Option Agreement dated November 1, 2001 between Western Gas Resources, Inc., and Peter A. Dea. (Filed as exhibits to the Stock Option Plan for Peter A. Dea on Form S-8 Registration Statement dated December 2001, and incorporated herein by reference.)

10.25 Seventh Amendment dated September 27, 2001 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc., and NationsBank, as agent, and the Lenders. (Filed as exhibit 10.25 to Western Gas Resources, Inc., 10-K for the year ended 12/31/01 and incorporated herein by reference).

10.26 Eighth Amendment dated February 25, 2002 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc., and Bank of America, N.A. (formerly NationsBank) as agent and the Lenders. (Filed as exhibit 10.26 to Western Gas Resources, Inc., 10-Q dated March 31, 2002 and incorporated herein by reference).

10.27 Ninth Amendment dated April 25, 2002 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc., and Bank of America, N.A. (formerly NationsBank) as agent and the Lenders. (Filed as exhibit 10.16 to Western Gas Resources, Inc., 10-Q dated March 31, 2002 and incorporated herein by reference).

10.28 Tenth Amendment dated January 3, 2003 to Loan Agreement dated April 29, 1999 by and among Western Gas Resources, Inc., and Bank of America, N.A. (formerly NationsBank) as agent and the Lenders.

10.29 Third Amended and Restated Master Shelf Agreement dated as of December 19, 1991 and effective as of January 13, 2002 by and between Western Gas Resources, Inc., and the Prudential Insurance Company of America, Pruco Life Insurance Company, Prudential Investment Management, Inc., and certain other Prudential Affiliates.

11.1 Statement regarding computation of per share earnings.

21.1 List of Subsidiaries of Western Gas Resources, Inc.

23.1 Consent of PricewaterhouseCoopers LLP.

23.2 Consent of Netherland, Sewell & Associates, Inc.

99.1 Certification by Peter A. Dea, President and Chief Executive Officer, and William J. Krysiak, Executive Vice President - Chief Financial Officer required by Sarbanes-Oxley Act of 2002.

(b) Reports on Form 8-K:

A report on Form 8-K was filed on October 25, 2002 announcing the plaintiff's filing of a complaint for declaratory relief in Western Gas Resources, Inc. and Lance Oil & Gas Company, Inc. v. Williams Production RMT Company., Civil Action No. CO2-10-394, District Court, County of Sheridan, Wyoming.

A report on Form 8-K was filed on November 26, 2002 announcing the redemption of all outstanding shares of the Company's $2.28 Cumulative Perpetual Preferred Stock and the de-listing with the New York Stock Exchange of that security.

A report on Form 8-K was furnished on November 13, 2002 providing an update to the Company's 2002 operational guidance.

A report on Form 8-K was furnished on February 21, 2003 announcing the Company's 2002 Results of Operations.

A report on Form 8-K was furnished on February 21, 2003 providing the Company's operational guidance for 2003.

(c) Exhibits required by Item 601 of Regulation S-K. See (a) (3) above.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Denver, State of Colorado on March 21, 2003.

WESTERN GAS RESOURCES, INC.
(Registrant)

By: /s/ Peter A. Dea
Peter A. Dea
Chief Executive Officer, President and Director

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

| | | |
|---|---|---|
| /s/ Brion G. Wise<br>Brion G. Wise | Chairman of the Board | March 21, 2003 |
| /s/ Walter L. Stonehocker<br>Walter L. Stonehocker | Vice Chairman of the Board | March 21, 2003 |
| Bill M. Sanderson | Director | |
| /s/ Lanny F. Outlaw<br>Lanny F. Outlaw | Director | March 21, 2003 |
| /s/ Richard B. Robinson<br>Richard B. Robinson | Director | March 21, 2003 |
| /s/ Dean Phillips<br>Dean Phillips | Director | March 21, 2003 |
| /s/ Ward Sauvage<br>Ward Sauvage | Director | March 21, 2003 |
| /s/ James A. Senty<br>James A. Senty | Director | March 21, 2003 |
| /s/ Joseph E. Reid<br>Joseph E. Reid | Director | March 21, 2003 |
| /s/ William J. Krysiak<br>William J. Krysiak | Executive Vice President -Chief Financial Officer<br>(Principal Financial and Accounting Officer) | March 21, 2003 |

**Reconciliation of Net Income to**
**Cash Flow before Working Capital Adjustments:**
(Dollars in thousands)

| | Year Ended December 31, 2002 | 2001 | 2000 |
|---|---|---|---|
| Net income | $ 50,589 | $ 95,637 | $ 56,108 |
| Add income items that do not affect operating cash flows: | | | |
| Depreciation, depletion and amortization | 77,005 | 64,162 | 57,919 |
| Deferred income taxes | 19,614 | 42,815 | 32,712 |
| Distributions less than equity income, net | (2,906) | (29) | (1,137) |
| (Gain) Loss on sale of property and equipment | 948 | (10,748) | (9,406) |
| Non-cash change in fair value of derivatives | 13,788 | (19,906) | - |
| Compensation expense from re-priced stock options | 224 | 170 | 1,879 |
| Foreign currency translation adjustments | 283 | 440 | 1,022 |
| Other non-cash items | 1,525 | 965 | 782 |
| Cash flow before working capital adjustments | $ 161,071 | $ 173,506 | $139,879 |

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# Investor Information

### Corporate Offices

1099 18th Street
Suite 1200
Denver, Colorado 80202

### Stock Information

New York Stock Exchange
Common Stock: WGR
Cumulative Convertible Preferred Stock: $2.625 WGR pfA

### Annual Meeting

The annual meeting of stockholders is scheduled to be held on May 16, 2003, at 10:00 a.m., at the Embassy Suites Hotel, 1881 Curtis Street, Denver, Colorado, 80202. A formal notice of the meeting and a proxy statement will be distributed on or about April 16, 2003, to stockholders of record at the close of business on March 28, 2003.

### Independent Accountants

PricewaterhouseCoopers LLP
Denver, Colorado

### Transfer Agent and Registrar

EquiServe Trust Company, N.A.
P.O. Box 43010
Providence, RI 02940
(800) 736-3001
www.equiserve.com

### Direct Deposit of Dividends

The Company offers direct deposit of dividends at no additional cost. To take advantage of this service, contact EquiServe Trust Company, N.A. at (800) 736-3001.

### Additional Information

Western's Quarterly Reports on Form 10-Q and Annual Report on Form 10-K are available upon request by calling (800) 933-5603. To access information on-line, visit our Web site at www.westerngas.com.

### Investor Contact

Financial analysts and investors may obtain additional information by contacting Ron Wirth, Director of Investor Relations, at (800) 933-5603, (303) 252-6090 (direct), or rwirth@westerngas.com.

### Information Regarding Forward-Looking Statements

Except for certain historical facts, the information presented herein consists of forward-looking statements, projections and estimates within the meaning of the Private Securities Litigation Reform Act of 1995, which can be identified by the use of forward-looking terminology, such as "may," "intend," "will," "expect," "anticipate," "estimate," or "continue" or the negative thereof or other variations thereon or comparable terminology. This Annual Report contains forward-looking statements regarding the expansion of our gathering operations, our project development schedules, our budgeted capital expenditures, success of our drilling activities, our marketing plans and anticipated volumes through our facilities and from production activities that involve a number of risks and uncertainties, including the composition of gas to be treated and the drilling schedules and success of the producers with acreage dedicated to our facilities. In addition to the important factors referred to herein, numerous other factors affecting our business generally and in the markets for gas and NGLs in which we participate, could cause actual results to differ materially from our projections in this Annual Report.

**Common Stock Statistics**

| | High | Low | Last | Dividends Paid |
|---|---|---|---|---|
| **2002** | | | | |
| 1st Quarter | 37.50 | 28.22 | 37.22 | 0.05 |
| 2nd Quarter | 39.98 | 36.10 | 37.40 | 0.05 |
| 3rd Quarter | 36.41 | 27.34 | 31.25 | 0.05 |
| 4th Quarter | 38.00 | 30.77 | 36.85 | 0.05 |
| **2001** | | | | |
| 1st Quarter | 34.45 | 24.11 | 32.25 | 0.05 |
| 2nd Quarter | 43.70 | 30.46 | 32.59 | 0.05 |
| 3rd Quarter | 34.70 | 23.90 | 26.03 | 0.05 |
| 4th Quarter | 35.65 | 25.01 | 32.32 | 0.05 |

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Western Gas Resources, Inc. • 1099 18th Street, Suite 1200, Denver, CO 80202
303-452-5603 • www.westerngas.com

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