WESTERN GAS RESOURCES

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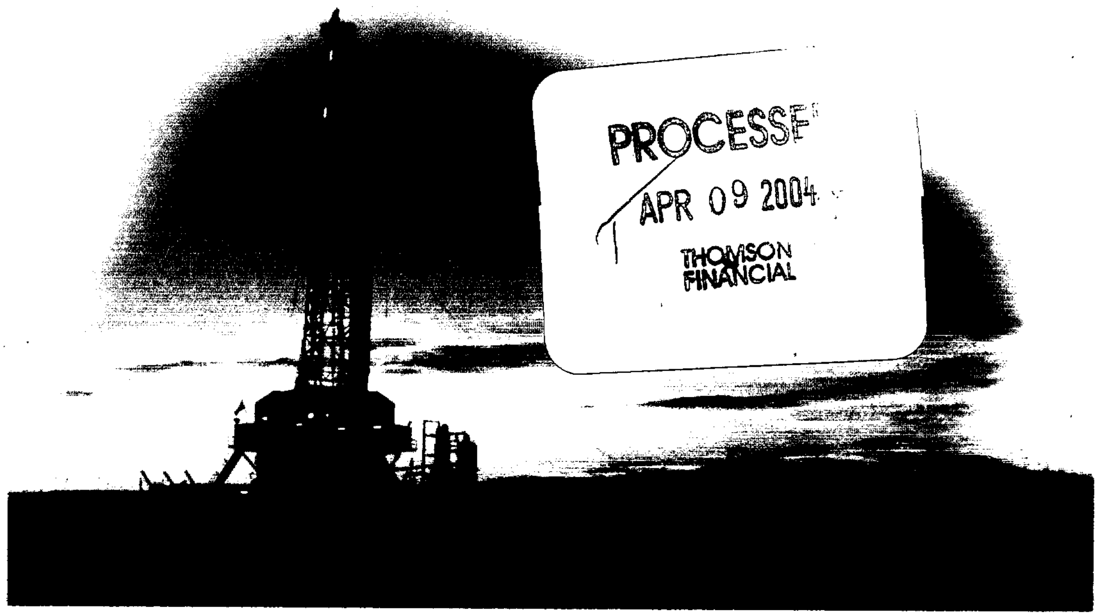
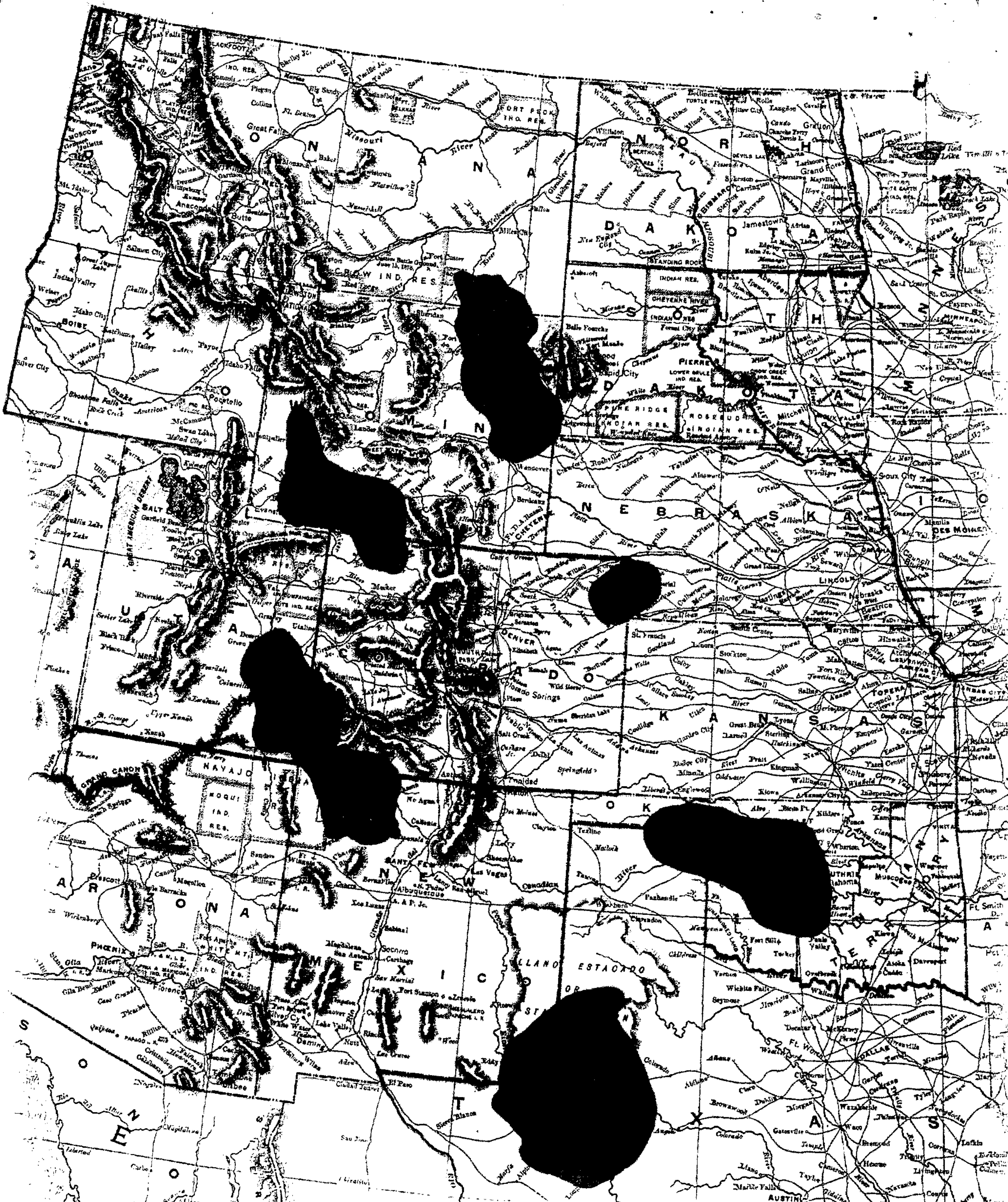


ANNUAL REPORT 2003



Western Gas Resources operates in the most actively drilled basins in the Rocky Mountains, Mid-Continent and West Texas. Our fully integrated approach to producing unconventional natural gas provides a strategic advantage to maximize returns, control our own destiny and access new growth opportunities. We are expanding our operations in existing and to new projects to provide long-term value for our shareholders and develop reliable, clean-burning natural gas.

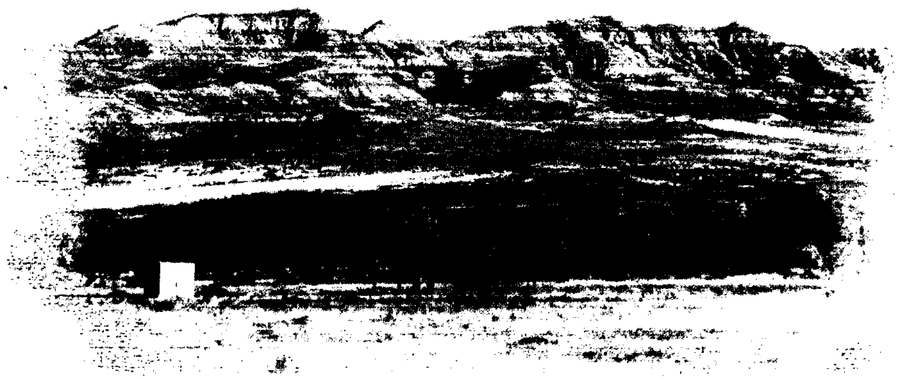
Dear Shareholders

Western Gas Resources continues to successfully execute its strategy as a premier developer of unconventional natural gas in the resource-rich Rocky Mountain West. We have successfully positioned ourselves in the Powder River Basin coal bed methane (CBM) development and the Pinedale Anticline in the Green River Basin, two of the most significant onshore natural gas discoveries in the U.S. in the last decade. These two Wyoming areas provide Western with ten or more years of potential drilling inventory.

We experienced another strong year operationally, delivering exceptional financial results to our shareholders with a focus on steady growth and solid returns. Strong commodity prices, year over year volume growth in both our upstream and midstream operations and solid marketing results led to our excellent 2003 performance. Our integrated approach to the natural gas business continues to provide Western with a competitive advantage in the Rocky Mountain region to maximize profitability and control our own destiny with timely and efficient connection of new producing wells.

Western recorded net income of $84.2 million in 2003, the second highest in our 26-year history and delivered a 29 percent return to our shareholders from stock appreciation and dividends. In fact, Western was recognized by *Forbes* magazine as one of the Platinum 400 Best Big Companies in America, and had the highest five-year return to shareholders in the oil and gas industry group. Cash flow before working capital adjustments of $215.7 million was the highest on record for our Company. Importantly, we delivered our excellent 2003 performance while reducing our debt to capitalization ratio net of cash to 36 percent, the lowest level in a decade.

We experienced double-digit growth in both production and reserves for the sixth consecutive year. Net production increased ten percent to 52.6 Bcfe and proven reserves grew 16 percent to 685 Bcfe, while operating profit from exploration and production operations increased 53 percent. We participated in drilling over 600 wells with a 99 percent success rate and finding and development costs of approximately $0.58 per Mcfe. Our gathering throughput volumes increased 13 percent to 1.34 Bcfd, contributing to a 35 percent increase in operating profit from the midstream business. Gathering volumes reached record levels in the Powder River, Green River and Anadarko Basins as we responded



CBM wellheads in the Powder River Basin blend in with the environment.

to increased producer activity and expanded operations for future growth.

In 2004, we plan to drill a total of 925 gross wells and are encouraged by progress of the permitting process to timely access drilling on federal lands. Within the Powder River Basin CBM play, we are projecting an 800-well drilling program and expect to participate in 90 wells in the Pinedale Anticline, nearly twice the number of wells compared to a year ago. We also plan to expand midstream operations in both areas to accommodate continued growth in the years ahead. An additional 35 wells will be drilled in new or expanding areas in 2004.

Our exploration and acquisition team continues to pursue growth opportunities in the Rocky Mountain region. We acquired significant leasehold in a promising new natural gas play in northeastern Colorado and plan to drill 20 wells in 2004 to further test the play. Several other exploration projects are in various stages of leasing, technical evaluation and drilling plans to capture new growth opportunities in unconventional gas.

As we carry the positive momentum of 2003 forward, we will continue to implement our focused strategy of developing Rocky Mountain natural gas and maximizing free cash from our high-quality midstream and marketing operations. An increase in drilling in the prolific Big George coal and highly successful Pinedale Anticline should allow us to further evaluate and develop our 2.1 Tcf of unbooked, unrisked, probable and possible reserves under lease. The corresponding gathering and processing volume growth would allow our midstream and marketing segments to continue to deliver solid earnings to our shareholders.

The energy and cooperative spirit of our employees combined with our strong leadership team optimizes the Company's performance and profitability. I want to sincerely thank them for their hard work and dedication as we advance our goal of being a leading developer of unconventional gas resources in the Rocky Mountain region. I also want to thank you, our shareholders, for the loyalty and trust you have placed in us as we work hard to create additional value.

Peter A. Dea

Peter A. Dea
President and Chief Executive Officer

CEO Perspective

A Conversation with Peter Dea

Q Why natural gas?

A Natural gas is the most dependable, clean-burning and environmentally friendly fuel, providing 24 percent of the energy used in the U.S. American families and businesses rely on natural gas as their energy source for heating, cooling and electricity. Industry has responded with substantial investment in the exploration, development and transportation of natural gas.

Development of natural gas benefits our country in many ways. It secures domestic energy resources, creates jobs and supports our infrastructure through tax payments. Overall, the gas industry helps sustain the quality of life for millions of Americans.

Q Is there a shortage of natural gas?

A No. There is an abundant supply of natural gas reserves in our country. Total U.S. recoverable natural gas resources are estimated at 1,127 Tcf. Our challenge is to obtain timely access to these reserves so we can proceed with developing our nation's natural gas supply. In the longer term, Alaskan gas and liquefied natural gas (LNG) will provide additional supply.

Currently, natural gas demand slightly exceeds U.S. production. Supply in the U.S. is challenged by steeper declines of base production in mature basins, lower productivity per well and increasing finding and development costs. Further development of the Rocky Mountain region is necessary to meet the needs of U.S. gas supply.

Q Why the Rockies?

A According to the National Petroleum Council, five western states, including Colorado and Wyoming, have 41 percent of the proven and potential gas reserves in the U.S. The Rocky Mountain basins contain numerous unconventional gas reservoirs including coal seams, low permeability or 'tite' gas sands, and biogenic shale. In 2001 and 2002, 78 and 31 percent, respectively, of total U.S. gas reserve additions came from the Rockies.

Western has operated in gas producing basins in the Rocky Mountain region for almost three decades. Our expertise in all facets of unconventional gas and substantial leasehold positions in the Powder River and Green River Basins combined with the vast potential of the region support our focus in the Rocky Mountains.

Q What are your views on high gas prices?

A Millions of Americans are experiencing economic pressure caused by higher energy prices. While current conditions certainly create positive market fundamentals, Western benefits from a long-term balanced supply/demand environment consisting of steady supplies and stable prices. Timely access to natural gas resources and advancing energy efficiency, conservation and research on renewable energy sources should be priorities in a balanced energy policy.

Western Gas and the industry in general have demonstrated their commitment to increase domestic natural gas supply through significant capital investment and responsible development. Western is an active supporter of Energy Outreach providing financial assistance to low-income families for energy needs. Increasing the supply of natural gas and more aggressive conservation will lower the price and help us sustain the quality of life for Americans at affordable prices.

Q Why Western?

A For its size, Western has an enviable long-term inventory of low-risk, low-cost and high-return development drilling in two of the largest natural gas fields discovered in the onshore U.S. in the last decade. These legacy assets have placed Western at or near the top of industry for three- and five-year annualized return to shareholders, production and reserve growth per share, and the lowest finding and development costs.

High-quality midstream assets are either fully integrated with producing properties to accelerate present value by the timely connection of our reserves, or they are profitable stand-alone operations in prolific natural gas basins. In either case, the gathering and processing business provides a platform of solid earnings.

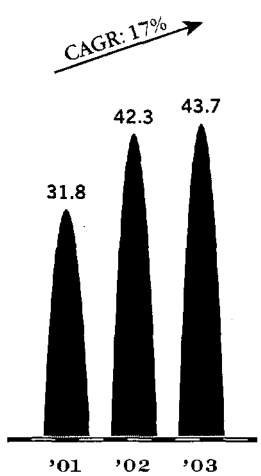
We intend to maintain a strategic focus on existing and new high-quality projects leveraging our expertise in unconventional gas resources and fully integrated operations to continue our solid track record into the future.

"...Western has an enviable long-term inventory of low-risk, low-cost and high-return development drilling..."

Powder River Basin Coal Bed Methane

The Powder River Basin coal bed methane (CBM) development is one of the most prolific natural gas discoveries in the onshore U.S. in the last decade. It is an important contributor of natural gas supply for America and has become a world-class play with over one Tcf of gas produced and an estimated 20 Tcf or more of gas remaining. Western is the largest leaseholder, gatherer and transporter and, with our co-developer, the largest producer of natural gas in the play.

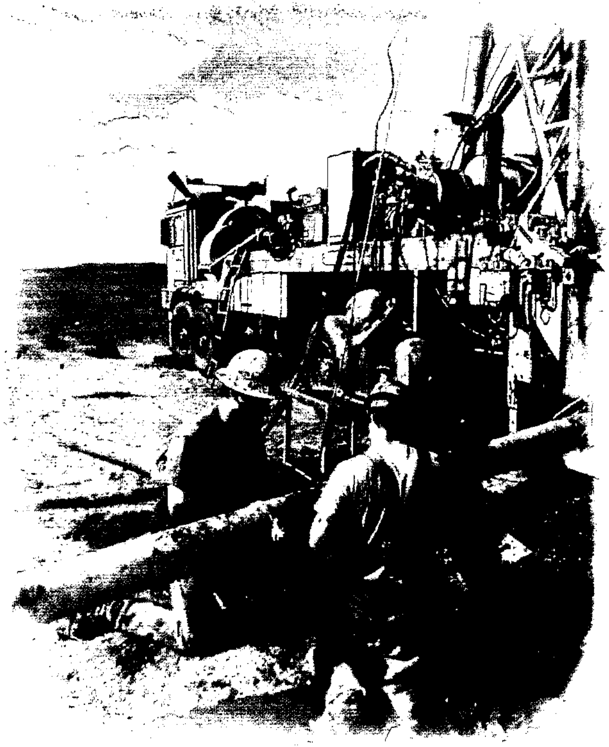
CBM Net Production Growth
(Bcf)



During 2003, Western drilled 536 gross CBM wells and increased net production three percent to 43.7 Bcf. We plan to drill approximately 800 gross wells in 2004. The Bureau of Land Management is planning to issue 3,000 federal drilling permits in 2004, which should provide us with more than sufficient permits to meet our 2004 plans. Net CBM production is expected to be relatively flat in 2004 due to previous permitting delays, declines in Wyodak coal production and the normal 12 to 24 month dewatering period for the Big George coals. However, we expect a 10 to 15 percent increase in 2005 as development expands in the Big George and related coals.

Western is the largest leaseholder, gatherer and transporter and, with our co-developer, the largest producer of natural gas in the play.

Net proved reserves for the Powder River Basin CBM were 326 Bcf at year-end 2003. Unbooked, unrisked, probable and possible reserves net to Western for the entire play remain at 1.9 Tcf due to the continued expectation of significant reserves in the deeper and thicker Big George and related coals.

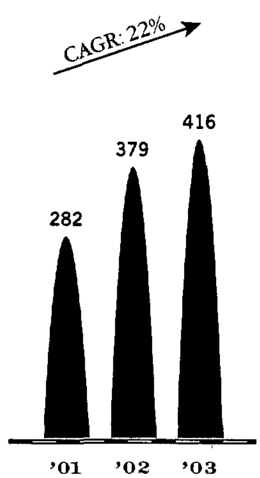


CBM drilling operations are expected to increase in the Powder River Basin in 2004.

Year-end 2003 proved, probable and possible reserves were evaluated by an independent engineering firm in a full reserve report of the Company's leasehold.

Eighty-five Bcf of year-end reserves are related to the Big George coal, a 73 percent increase from 2002. The Big George wells are expected to have two to three times the reserves as the Wyodak coals. Industry-wide, Big George production increased approximately 100 percent to 120 MMcfd during 2003. Western has drilled 768 gross wells in this coal as of year-end 2003. Of that total, 337 wells are producing gas and the remainder are dewatering or awaiting hookup. The Big George is expected to experience continued solid growth in 2004 and accelerate in 2005. Three development areas for Western and its co-developer in the Big George were producing approximately 39 MMcfd gross as of February 2004. Six or more additional Big George pilots are expected to begin producing gas this year. Western and its co-developer expect to have drilled over 1,200 Big George wells in total by year-end 2004.

CBM Volumes Gathered
(MMcfd)



Our integrated approach to the Powder River Basin CBM provides incremental cash flow and allows us to control our own destiny. Our extensive owned and operated gathering operations allow us to coordinate the pace and timing of connecting our CBM wells and control the placement and maintenance of compression. Our co-developer and other third-party producers also utilize our efficient gathering and compression services, which provide additional revenues and cash flow to the Company.

Gathering and compression will be added in the Powder River Basin in 2004 to handle new CBM volumes from the Big George coals.

The Powder River Basin CBM development is a company-building play for Western as we drill into our ten or more year inventory of well locations on our existing leasehold.

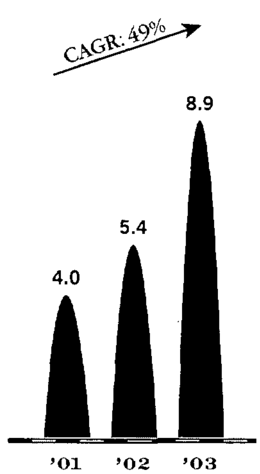
CBM gathering volumes, which include our equity and third-party gas, increased 10 percent to 416 MMcfd in 2003. Approximately 113 MMcfd of the total volumes gathered were also transported on our wholly owned MIGC pipeline to a major interstate pipeline connection and 256 MMcfd was moved on our 13 percent owned and operated Fort Union gathering system. In total, Fort Union handled 479 MMcfd of CBM volumes, including third-party volumes. We continue to be the largest gatherer and transporter of CBM in the Basin. We are currently constructing three large diameter gathering lines to new Big George coal areas, each capable of handling up to 100 MMcfd of gas.

The Powder River Basin CBM development is a company-building play for Western as we drill into our ten or more year inventory of well locations on our existing leasehold.

Greater Green River Basin

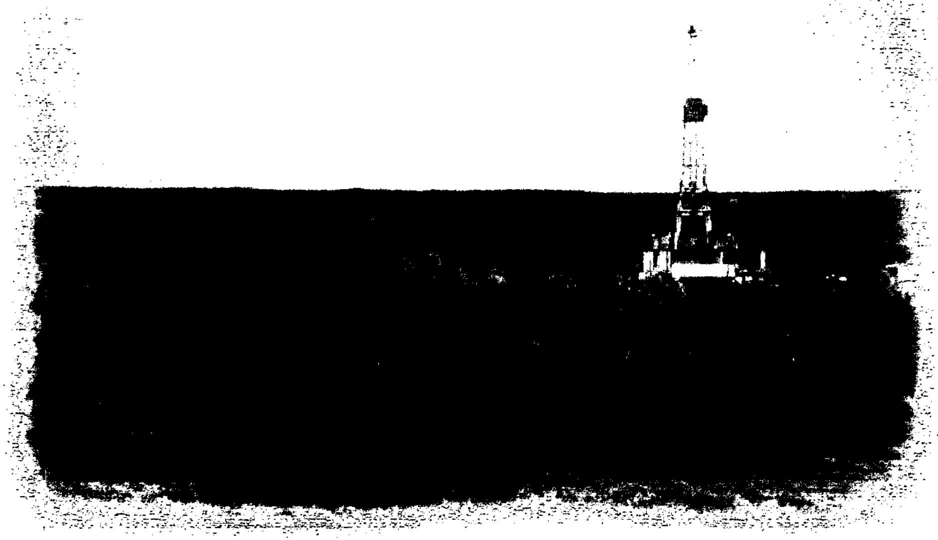
The Greater Green River Basin is a significant area for Western and exemplifies the success of our fully integrated natural gas operations. Industry experts believe the Green River Basin area is one of the largest natural gas resources in the U.S. Western is involved in the Pinedale Anticline and Jonah Field, two of the most productive onshore U.S. gas discoveries in the last decade. These two areas alone are estimated by industry to hold 12 to 24 Tcf of economically recoverable reserves.

Net Production Growth
(Bcfe)



Western is involved in the Pinedale Anticline and Jonah Field, two of the most productive onshore U.S. gas discoveries in the last decade.

Western has approximately 179,000 net acres in the Greater Green River Basin, including an approximate ten percent interest across a majority of the Pinedale Anticline and in three sections of the Jonah Field. Net proved reserves at year-end 2003 increased 106 percent to 359 Bcfe while our unbooked, unrisked, probable and possible net reserves increased to 198 Bcfe based on 40-acre spacing. Additional meaningful reserves could be recovered if the Pinedale Anticline is downspaced to 20 acres per well. The combination of expanding the productive limits of the Pinedale Anticline, widespread success in the Mesaverde and Lance formations and 40-acre downspacing has contributed to the increase in reserves. We acquired a previously non-operated interest in the Sand Wash Basin area, which added 10.6 Bcfe of reserves and 0.4 Bcfe of production in 2003.

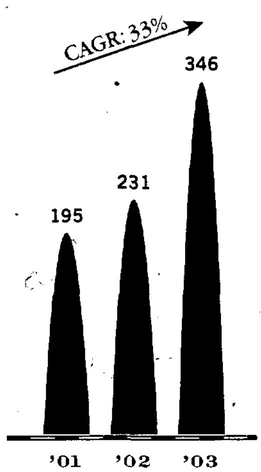


Drilling on the prolific Pinedale Anticline is expected to increase significantly in 2004.

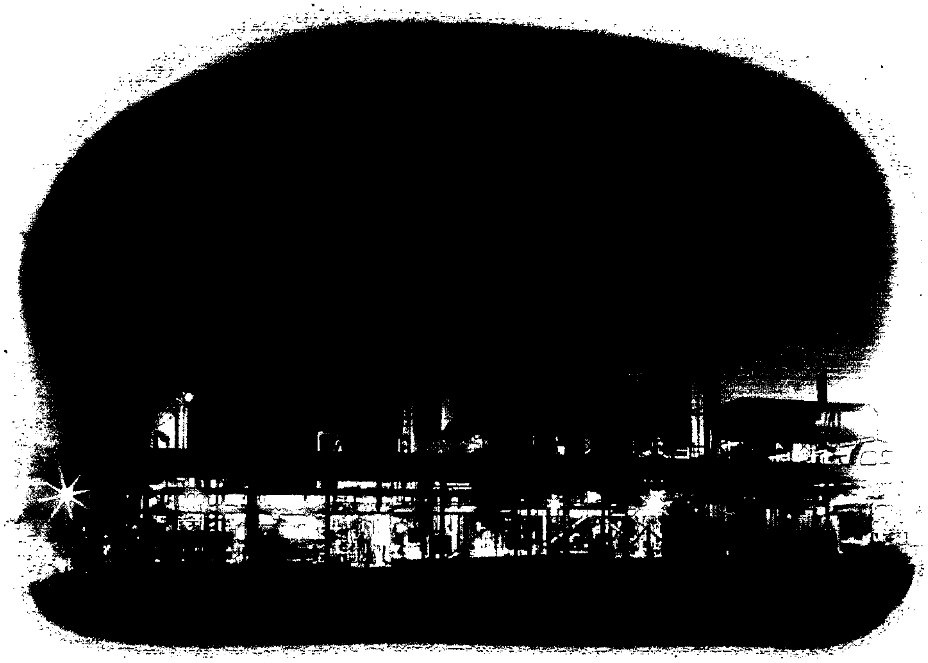
Production increased approximately 66 percent to 8.9 Bcfe, of which 7.5 Bcfe were attributable to the Pinedale Anticline and Jonah Field. The Company participated in 63 gross wells in the Greater Green River Basin, including 53 gross wells on the Anticline. In 2004, we expect to participate in 90 gross wells on the Pinedale Anticline as part of a 104-well program in the Greater Green River Basin. The planned increase in 2004 is partially attributable to 20-acre pilot programs based on similar success in Jonah Field. If successful, Western could participate in up to 1,000 potential new gross locations on its leasehold over the next 10 to 15 years. We expect net production volumes to increase approximately 80 percent in 2004 and 25 percent in 2005 based on success of current drilling plans.

We expect to see continued growth in the Greater Green River Basin in both our upstream and midstream operations during the next several years as this prolific natural gas resource is developed.

Gas Volumes Gathered
(MMcfd)



Our midstream operations in the Greater Green River Basin also experienced significant expansion in 2003 to accommodate growing production from the Pinedale Anticline. Gathering volumes increased 50 percent to 346 MMcfd, including 64 MMcfd from gathering system acquisitions. We completed two expansions of our 50 percent owned Rendezvous gathering system in 2003. Rendezvous has current capacity of 350 MMcfd and can be expanded to 550 MMcfd by adding



The Granger Plant in southwest Wyoming was expanded to handle increasing volumes from the Pinedale Anticline.

compression. Rendezvous was moving approximately 285 MMcfd in December 2003 to two processing facilities in the area, including our Granger Plant. We recently added 100 MMcfd of processing capacity at Granger, which increased total processing capacity to 275 MMcfd.

In the eastern portion of the Greater Green River Basin, the gathering systems we acquired in the Wamsutter Arch, Red Desert and Washakie Basin areas in early 2003 have been integrated with our existing Red Desert Plant. We expect to double processed volumes at Red Desert in 2004 as a result. New exploration opportunities in the area included two gross wells with an additional five gross wells budgeted for 2004. We anticipate this area of the Basin could become a new core area for Western.

We expect to see continued growth in the Greater Green River Basin in both our upstream and midstream operations during the next several years as this prolific natural gas resource is developed.

Midstream & Marketing Operations

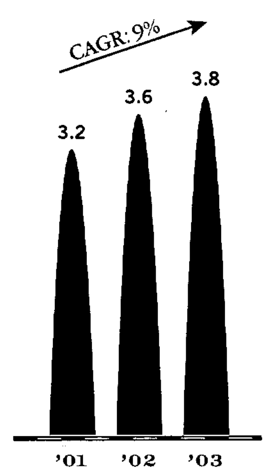
We have an extensive gathering, processing and marketing infrastructure in some of the most actively drilled basins in the U.S. and key transportation assets in the Powder River Basin. Our concentrated midstream operations in West Texas, western Oklahoma and the San Juan Basin of New Mexico generate strong cash flow and operating income and complement our fully integrated midstream and upstream businesses in the Powder River and Green River Basins of Wyoming.

Our reliable performance and low-cost structure adds tremendous value to our own operations and distinguishes Western as an industry leader among our peers in providing quality natural gas services.

The strong commodity price environment in 2003 stimulated strong drilling activity in each of our operating areas. Gathering volumes increased in the Powder River, Green River, Anadarko and San Juan Basins, resulting in a 13 percent increase to 1.34 Bcf per day from 2002. We connected a record 209 wells in Oklahoma and hooked up approximately 200 wells in West Texas from infill drilling activity in the prolific Spraberry Trend.

Operating income from our midstream operations increased 35 percent to $126.6 million in 2003 compared to 2002. We expect high levels of drilling activity in 2004 to drive continued growth in gas gathering volumes. In 2004, we will add new projects to expand our gathering and processing operations in the Powder River, Green River and Anadarko Basins and continue to pursue midstream acquisition opportunities that complement our existing asset base.

Connected Reserves
(Tcf)



Upgraded compression at Midkiff/Bendum in West Texas reduced fuel costs and enhanced our low-cost operations.

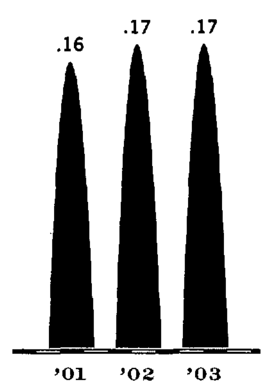
The low-cost, high-efficiency performance of our midstream facilities combined with the knowledge and integrity of our operations team allows us to compete successfully for new gas volumes in our core areas. We have approximately 3.8 Tcf of proven producing gas reserves dedicated to our systems. The efforts of our employees in 2003 resulted in an impressive per unit operating cost of $0.17 per Mcf.

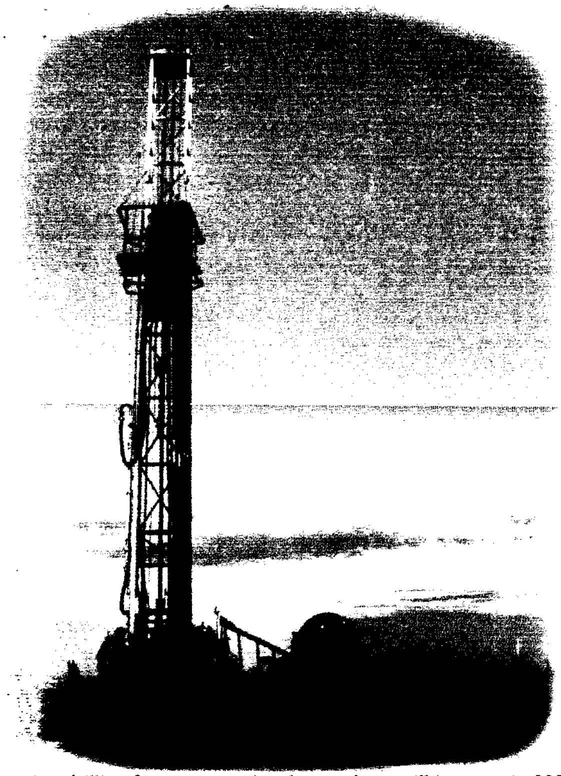
Our reliable performance and low-cost structure adds tremendous value to our own operations and distinguishes Western as an industry leader among our peers in providing quality natural gas services.

New technological programs have decreased costs, increased the efficiency of our workforce and increased the economic benefit to our customers. New Internet software programs were implemented in 2003 to enhance compliance management and adopt best practices throughout the Company. We are committed to safety, regulatory compliance, maximizing efficiency, productivity and service to our customers and providing stability to earnings.

Our integrated approach to natural gas is complemented by our gas and natural gas liquids (NGLs) marketing operations. We market gas and NGLs produced at our wells, processed at our plants and purchased from third parties to end-users, local distribution companies, pipelines and other marketing companies. The primary goal of our marketing department is to maximize prices received for our equity volumes of natural gas and NGLs. We utilize a consistent hedging program, firm transportation contracts from the Rocky Mountain region to higher-priced Mid-Continent markets and gas storage positions to optimize the value of our equity gas and provide opportunities during seasonal price variations.

Low Operating Costs
($/Mcf of gas volumes gathered)





Exploration drilling for unconventional natural gas will increase in 2004.

Exploration

Western is actively seeking new company-building growth projects through grassroots exploration, joint ventures and acquisitions. Our strategy is focused on identifying new unconventional natural gas resources in the Rocky Mountain region, which have the potential for repeatable drilling of low-cost, low-risk reserves and capitalize on our fully integrated upstream, midstream and marketing expertise.

Our expertise in unconventional resources and fully integrated business model are a perfect fit for the growth opportunities within the gas-rich Rockies.

During 2003, we increased our leasehold in a new natural gas play in northeast Colorado and western Nebraska to 340,000 net acres. Preliminary test results from two test wells are encouraging. We are targeting the Niobrara Formation, an unconventional biogenic gas reservoir. We plan to drill 20 wells and shoot a second 3-D seismic program in 2004 to evaluate our exploratory leasehold, which has the potential to be a fairway-type play. If successful, we also expect to construct and operate gathering systems to deliver the gas to market.

Our expertise in unconventional resources and fully integrated business model are a perfect fit for the growth opportunities within the gas-rich Rockies.

We have identified three additional basins or areas where we have begun to acquire acreage or are actively evaluating acquisition and partnership opportunities. We believe we will be able to acquire and develop new company-building opportunities to maintain consistent growth balanced with solid returns for the next decade.

Powder River Basin CBM water is used by livestock and wildlife.

Environmental & Safety

Western contributes to a healthy environment by providing Americans their clean-burning fuel of choice and doing so in an environmentally responsible manner.

Our core values include responsible development of natural gas and a safe work environment for our employees. Our leadership role in the development of industry best practices in the Powder River Basin; participation in SafeStart, a new behavior-based safety initiative; and the STAR Program, a voluntary partnership between industry and the Environmental Protection Agency (EPA) demonstrate this commitment.

In the Powder River Basin, our field managers lead an industry-wide best practices effort. This effort includes mitigation of surface impact by minimizing surface separation tanks, installing small earth-toned wellhead covers and the reclamation and reseeding of abandoned well locations. We also work closely with landowners on beneficial uses of produced potable water, road locations and noise abatement.

The SafeStart Program is designed to create an accident-free work environment. The program educates employees to recognize unsafe conditions before an accident occurs. Most of our workforce has been trained in the program resulting in fewer accidents.

Our core values include responsible development of natural gas and a safe work environment for our employees.

In 2003, Western received the Natural Gas STAR Processing Partner of the Year award. This recognizes the most outstanding performance of STAR partners in reducing methane emissions and implementing new emissions-reducing practices.

Western's Officer Team (left to right): Peter Dea, Ed Aabak, Bill Krysiak, John Walter, Burt Jones, Vance Blalock, Dave Keanini, Brian Jeffries, John Chandler and Jeff Jones.

Officers

PETER DEA, 50
President & Chief Executive Officer

JOHN CHANDLER, 47
Executive Vice President &
Chief Operating Officer

BILL KRYSIAK, 43
Executive Vice President &
Chief Financial Officer

JOHN WALTER, 58
Executive Vice President &
General Counsel

ED AABAK, 52
Executive Vice President, Midstream

VANCE BLALOCK, 50
Vice President & Treasurer

BRIAN JEFFRIES, 46
Vice President, Marketing

BURT JONES, 44
Vice President, Business Development

JEFF JONES, 50
Vice President, Production

DAVE KEANINI, 43
Vice President, Engineering,
Environmental & Safety

Directors

JAMES SENTY, 68 (A,C,N)
Chairman of the Board
Chairman, The Park Bank

WALTER STONEHOCKER, 79 (E,A)
Vice Chairman
Retired Senior Vice President

PETER DEA, 50
President & Chief Executive Officer

DEAN PHILLIPS, 72 (C,N)
President of Heetco, Inc.

JOSEPH REID, 75 (A,C,N)
Independent Oil & Gas Consultant
Retired Chief Executive Officer &
President of Meridian Oil Company

RICHARD ROBINSON, 55
Partner of Robinson & Diss, P.C.

BILL SANDERSON, 74 (E,A,N)
Retired President & Chief Operating Officer

WARD SAUVAGE, 78 (E,C)
President of Sauvage Gas Company

BRION WISE, 58 (E)
Former Chairman &
Chief Executive Officer

E Member Executive Committee
A Member Audit Committee
C Member Compensation Committee
N Member Nominating & Governance Committee

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, 2003 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, 2003 was $837,578,491.

The number of shares outstanding of the only class of the registrant's common stock, as of March 3, 2004, was 34,182,837.

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 7, 2004.

Western Gas Resources, Inc.
Form 10-K
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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, or NGLs. In our upstream operations, we explore for, develop and produce natural gas reserves primarily in the Rocky Mountain region. In our midstream operations, which are comprised of three segments, 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, Greater Green River, and San Juan 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.

- ***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.

- ***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.

Historically, we have derived over 97% 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,					
	2003	%	2002	%	2001	%
Sale of gas	$ 2,463,016	85.7	$ 2,118,748	85.1	$ 2,866,424	85.5
Sale of natural gas liquids	346,108	12.0	309,513	12.4	424,115	12.6
Processing and transportation revenue	83,672	2.9	65,601	2.6	55,398	1.6
Price risk management activities	(21,385)	(0.7)	(8,884)	(0.3)	2,546	0.1
Other	2,599	0.1	4,720	0.2	4,679	0.2
	$ 2,874,010	100.0	$ 2,489,698	100.0	$ 3,353,162	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 Greater Green River Basins in Wyoming and Colorado and our midstream operations in west Texas, Oklahoma, and New Mexico. Since 2001, our long-term business plan has been to increase stockholder value by: (i) doubling proven reserves and equity production of natural gas from the level at December 31, 2001 over a 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 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 play, or CBM, and development in the Greater Green River Basin, and actively seek to add other core natural gas development projects. Overall, we hold drilling rights on approximately 1,043,000 net acres in these and other Rocky Mountain basins. At December 31, 2003, we had proved developed and undeveloped reserves of approximately 685 billion cubic feet equivalent, or Bcfe, of which 42% are proved developed producing reserves. In total this represents an increase of approximately 44% in our proved developed and undeveloped reserves from December 31, 2001. During 2003 our production of natural gas as compared to 2002 increased by 10% to 52.6 Bcfe. In total this represents an increase of approximately 47% in our average equity production of natural gas from 2001 and we replaced 283% of our 2003 production, primarily from drilling and proved undeveloped locations resulting from drilling. In the Powder River Basin, our future growth lies in over 10,000 potential well locations in the Big George, Wyodak and related coals if the play is fully successful. In the Greater Green River Basin, our reserve potential is in the development of 40-acre and 20-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 other core projects that are 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 additional leaseholds, proven and undeveloped reserves or companies with operations focused in this area. Toward this goal, we have acquired the drilling rights on approximately 340,000 net acres in northeast Colorado and southwest Nebraska.

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. In 2003, the throughput volume at our gathering and processing facilities averaged 1.3 billion cubic feet, or Bcf, per day and operating income contributed by these facilities was $126.6 million.

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 primarily on acreage dedicated by third parties to us or produced by us. 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. Although some of our plants have experienced natural declines in dedicated reserves, overall we have been successful in connecting additional reserves to more than offset these declines. At December 31, 2003, the estimated reserves connected to our midstream facilities totaled 3.8 trillion cubic feet, or Tcf. This includes estimated third-party reserves connected to our facilities, which are based upon our interpretation of publicly available well and production information and are not the result of audited reserve reports prepared for us, and our connected proven reserves in the Powder River and Green River Basins. During 2003, we spent approximately $54.7 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. For example, in February 2003, we acquired several 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 505 miles of gathering lines and, during December 2003, were gathering a total of 108 million cubic feet, or MMcf, per day.

Optimize Annual Returns. To optimize our annual returns, we will focus our efforts in our primary operating areas in the Powder River and Greater Green River Basins in Wyoming and Colorado, the Anadarko Basin in Oklahoma, the Permian Basin in west Texas, and the San Juan Basin in New Mexico. 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. 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. We routinely evaluate our business for methods to reduce our operating and administrative costs, including the implementation of automation and information technology.

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," "believe," "anticipate," "estimate," or "continue" or the negative thereof or other variations thereon or comparable terminology. This Form 10-K contains forward-looking statements regarding: our drilling schedules, success of our drilling activities, reserves and production volumes, our ability to obtain permits and our ability and associated costs to comply with governmental and environmental regulations, expansion of our gathering operations, the drilling success of the producers with acreage dedicated to our facilities, our gathering and transportation throughput, our budgeted capital expenditures, our marketing margins and volumes, our equity production subject to hedges, our liquidity, our future tax benefits and their projected use, our expected future cash flows and their impact on our impairment calculations, and the outcome of our ongoing litigation.

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 the results contemplated by the forward-looking statements in this Form 10-K. See further discussion in Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations", "Financial Statements and Supplementary Data - Notes to Consolidated Financial Statements - Note 2 - Summary of Significant Accounting Policies - Use of Estimates and Significant Risks" and our other documents on file with the Securities and Exchange Commission, or SEC.

Western Gas Resources, Inc. was incorporated in Delaware in 1989. Our principal offices are located at 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 SEC at http://www.sec.gov . Additionally, our Code of Business Conduct and Ethics, Code of Ethics for Senior Financial Management, Corporate Governance Guidelines and the charters of our Audit Committee, Compensation Committee and Nominating and Corporate Governance Committee are posted on our website and are available in print free of charge to any stockholder who requests them.

2004 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 opportunities available to us. In 2004, we anticipate capital expenditures of approximately \$243.5 million. We expect that the Rocky Mountain region will utilize approximately 87% or \$211.9 million of the 2004 budget. The 2004 capital budget is presented in the following table (dollars in thousands).

Type of Capital Expenditure	2004 Capital Budget
Gathering, processing, treating and pipeline assets	$ 97.0*
Exploration and production and lease acquisition activities	135.7
Information technology and other items	3.0
Capitalized interest and overhead	7.8
Total	$ 243.5

* Includes \$11.7 million for maintaining existing facilities.

The majority of our capital expenditures are expected to 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 $101.7 million, or 42% of our total capital program. Of this amount, approximately $70.1 million is planned to be spent on our share of drilling 800 gross wells and for production equipment and undeveloped acreage and $31.6 million for gathering lines and installation of additional compression units.

In the Greater Green River Basin we expect to invest approximately $98.3 million, or 40% of the total 2004 capital expenditure program. We plan to spend approximately $57.6 million to participate in approximately 104 gross wells, 90 of which are in the rapidly developing Pinedale Anticline area, and $40.7 million to expand gathering and compression services.

The remaining $43.5 million of our 2004 capital spending program is expected to be spent as follows: $32.7 million for well connections, expansions, exploration, maintenance and upgrade projects in our other operating areas, $7.8 million for capitalized interest and overhead and $3.0 million for administrative expenditures. Overall, we expect to spend $11.7 million on maintenance and upgrade projects for existing midstream facilities. Due to drilling, regulatory, commodity pricing and other uncertainties that are beyond our control, we can make no assurance that our capital budget for 2004 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, 2001 over a five year period. In order to achieve this goal, we will focus on continued development of our leasehold positions in the Powder River CBM development and the Greater Green River Basin. Each of our existing upstream projects is 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. Additionally, we are actively pursuing new exploration, development and producing property acquisition opportunities.

Our principal upstream operations are summarized in the following table:

Production Area	Gross Acres Under Lease At December 31, 2003	Net Acres Under Lease At December 31, 2003	Proven Reserves at December 31, 2003	Average Net Production for the Year Ended December 31, 2003*	Gross Productive Gas Wells at December 31, 2003	Net Productive Gas Wells at December 31, 2003
Powder River Basin CBM	1,042,000	529,000	326 Bcfe	124 MMcfe/day	3,258	1,547
Pinedale/Jonah Basin	166,000	31,000	330 Bcfe	21 MMcfe/day	145	16
Sand Wash Basin	175,000	148,000	29 Bcfe	4 MMcfe/day	13	13
Northeast Colorado	370,000	322,000	-	-	-	-
Other	13,000	13,000	-	-	10	2

* Represents net production sold.

Powder River Basin Coal Bed Methane. We continue to develop our Powder River Basin CBM reserves and expand the associated gathering system in northeast Wyoming. The Powder River Basin CBM 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 2003, we were the largest producer of natural gas. Additionally, Western is the largest gatherer of natural gas and, through our MIGC pipeline, we transport a significant volume of gas out of this basin.

At December 31, 2003, we held the drilling rights on approximately 529,000 net acres in this basin, and as of December 31, 2003, we had established proven developed and undeveloped reserves totaling 326.0 Bcfe, net, on a portion of this acreage, 52% of which are proven and developed. This represented an overall 21% decrease in proven reserves as compared to December 31, 2002. In total, as a result of our drilling and proved undeveloped locations resulting from drilling, we added 78.8 Bcfe of proven reserves in this play in 2003. More than offsetting these additions was production of 43.7 Bcfe during the year and downward revisions of existing reserves of 123.2 Bcfe. The downward revisions were largely due to a change in methodology for calculating gas content and reserves in the Wyodak coals warranted by unexpected pressure declines in the mature development area and due to drainage by offset wells. We, as well the State of Wyoming and the United States Department of Energy, have historically utilized gas content calculations based on adsorbed isotherm data for the Wyodak coals on the eastern side of the basin. This approach assumed that the coal was 100 percent gas saturated at a specific temperature and pressure. After in-depth analysis, we, in consultation with an independent engineering firm, concluded that the Wyodak is not fully saturated. It was then determined that desorbed gas content values, which is the volume of gas that is measured from a coal sample as it was depressured in a laboratory setting, more closely represents the actual gas content and reserves in the Wyodak coal in light of current field pressures.

The drilling operations in the Powder River Basin through December 31, 2003 have primarily focused on developing reserves in the Wyodak coal, which is located on the east side of the coal bed development. The drilling and completion cost for our CBM gas wells averaged approximately $136,000 per well during 2003, with average reserves per successful Wyodak well of approximately 213 MMcf. 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.

Proved reserves at December 31, 2003 included 85 Bcf from the Big George coal, primarily in the All Night Creek Unit. Our gross production from the Big George coal has continued to increase and in February 2004 was over 39 MMcfd from the All Night Creek Unit, Pleasantville and Kingsbury Unit development areas. Industry-wide Big George production was approximately 120 MMcfd as most recently reported by the State of Wyoming, representing an estimated 100 percent growth rate during the previous 12 months. In February 2004, we had 337 Big George wells that are dewatering and producing gas. An additional 148 Big George wells are dewatering and 283 Big George wells have been drilled and are in various stages of completion and hook-up in preparation for production.

We currently plan to participate in the drilling of a total of 800 gross wells in 2004. Our share of production sold from CBM wells in which we own an interest averaged approximately 124 MMcfe per day in 2003. This represents an increase of 4% from the average daily production sold in 2002. We currently anticipate daily production to remain relatively constant through the end of 2004. We expect that the rate of production will be somewhat limited in 2004 by the number of federal permits issued in 2003 and dewatering times in the Big George coal.

On April 30, 2003, the Bureau of Land Management, or BLM, issued the final Record of Decision, or ROD, for the Powder River Basin Oil & Gas Environmental Impact Statement, or EIS. The ROD requires additional surveys for plant and animal species, cultural surveys and noxious weed mitigation. We have filed permit applications for approval by the BLM under the terms of the new EIS, and although we have received federal permits for 201 wells since the issuance of the ROD and through February 15, 2004, we are unable to predict the rate at which permits will be granted in the future. Since the issuance of the final ROD, the BLM has been reviewing its permitting process in an effort to issue to industry a total of approximately 3,000 permits per year under the EIS.

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 our existing production is from wells draining into these areas. Most of our undeveloped prospects from the Big George formation are located in the Powder River drainage area. The Wyoming DEQ will require additional water management techniques, such as containment or treating, in these areas pursuant to the conditions described in the EIS referred to above. While we believe these additional requirements will add to the cost of development of this area, we do not believe they will have a significant impact on our results of operations, financial position or cashflows.

In October 2003, we settled on-going litigation with our co-developer in this area. Under the terms of the settlement agreement, both our co-developer and we each operate the drilling and production on approximately one-half of the jointly owned leasehold in the CBM development of the Powder River Basin of Wyoming. We began operating our portion of the properties on November 1, 2003.

During 2003, we expended approximately $43.0 million in the Powder River Basin coal bed project for drilling costs, production equipment and lease acquisitions. Our 2004 capital budget for the Powder River Basin coal bed project is estimated at $70.1 million; however, due to regulatory uncertainties, which are beyond our control, we can make no assurance that we will incur this level of capital expenditure during 2004.

Jonah/Pinedale Fields. Our upstream assets in the Green River Basin of southwest Wyoming are located in the Jonah Field and Pinedale Anticline areas. During 2003, we participated in 53 gross wells, or five net wells, in these areas, at a cost of $19.0 million and experienced a success rate of 100%. Our capital budget for 2004 in the Jonah Field and Pinedale Anticline areas provides for expenditures of approximately $43.1 million for drilling costs and production equipment. During 2004, we expect to participate in the drilling of 90 gross wells, or approximately nine net wells, on the Pinedale Anticline. 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 2004.

In October 2003, the Wyoming Oil & Gas Commission approved two pilot drilling programs to increase density on a portion of Western's Pinedale Anticline leasehold to two wells per 40 acres. We expect that approximately 60 wells will be drilled by two of Western's partners during the next 12 to 24 months to test the increased density concept, which would effectively result in 20-acre spacing.

The expected gross costs to drill a successful well in this area range from approximately $3.5 million to $5.0 million, depending on location of the well site and the depth of the well. Average well depths in this area range from approximately 13,000 feet to 14,200 feet, and average gross reserves per successful well approximate 6 to 10 Bcfe. During 2003, we produced and sold 7.7 Bcfe, net, from these areas. We had established proven developed and undeveloped reserves totaling 330 Bcfe, net, at December 31, 2003, of which 28% are proved developed producing reserves. This represents a 105% increase as compared to December 31, 2002. Results in 2003 reflected existing 40-acre downspacing and success in the deeper Mesa Verde sands in the Pinedale Anticline, which have added significant reserves. No proved reserves were attributed to 20-acre pilots at this time. 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, located in the Greater Green River Basin. During 2003, we produced 1.4 Bcfe from this acreage. At December 31, 2003, we had established proven developed and undeveloped reserves totaling 29 Bcfe on a portion of this acreage. This represents a 122% increase from the proved reserves at December 31, 2002, primarily as a result of the acquisition in the third quarter of 2003 of the stock of a private corporation for $12.9 million. In this acquisition, we acquired 11 Bcfe of proved reserves and approximately 11,000 net acres under lease.

We now own approximately 148,000 net oil and gas leasehold acres in this basin. The majority of this acreage is in the exploration phase and will be evaluated in future years. In 2003, we drilled an exploratory well, which encountered mechanical difficulties prior to reaching the targeted reservoir. This well has been plugged and abandoned. In connection with this well, we recorded a dry hole expense of approximately $1.8 million. In 2003, approximately $15.5 million was spent in this area. Our 2004 capital budget in this area provides for expenditures of approximately $11.3 million for our participation in the drilling of eight gross and net development wells and one exploratory well. 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 7,700 feet.

Exploration. We are also actively seeking to add additional upstream core projects that are focused on Rocky Mountain natural gas. We will utilize our expertise in exploration and low-risk development of tight-gas sands, coal bed methane and fractured shale plays to evaluate acquisitions of either additional leaseholds, proven and undeveloped reserves or companies with operations focused in the Rockies.

Toward this goal, as of January 31, 2004, we have acquired the drilling rights on approximately 390,000 gross acres, or approximately 340,000 net acres, in the northeastern area of the Denver-Julesburg Basin in northeast Colorado and southwest Nebraska. In the fourth quarter of 2003, we drilled two test wells in this area to further evaluate its potential. These wells are completed and are being flow tested to evaluate the overall play. We also plan to drill at least 15 test wells in this area in 2004. We are targeting the Niobrara formation at a depth of approximately 2,500 feet. The drilling and completion costs per gross well are expected to approximate $200,000 with possible gross reserves of 300,000 to 500,000 Mcfe per well.

In the fourth quarter of 2003, we also participated in two gross exploratory wells, or one net well, in the eastern Green River Basin. These wells also are waiting on completion. If these wells are successful, additional offset locations may be proposed.

During 2003, our capital expenditures in the exploration area totaled $8.1 million. Our capital expenditure budget for 2004 in the exploration area totals $11.2 million, primarily for our participation in drilling activities, seismic surveys and leasehold acquisition.

Production Information. Revenues derived from our producing properties comprised approximately 7%, 6% and 4% of consolidated revenues for the years ended December 31, 2003, 2002 and 2001, respectively. The operating profit (revenues and equity earnings from equity investments less product purchases and operating expenses) derived from our producing properties comprised approximately 40%, 33% and 24% of consolidated operating profit for the years ended December 31, 2003, 2002 and 2001, respectively. We expect both the revenues and operating profit derived from our producing properties to continue to increase commensurately with our production growth.

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

	Year Ending December 31,					
	2003		2002		2001	
State/Basin	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)
Colorado – Sand Wash Basin	1,340	6	900	6	547	3
Texas (1)	16	1	20	2	29	2
Wyoming:						
Powder River Basin	43,748	-	42,314	-	31,773	-
Green River Basin	7,118	68	4,167	45	3,165	40
Total	52,222	75	47,401	53	35,514	45

(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 last three years:

	Year Ending December 31,					
	2003		2002		2001	
State/Basin	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)	Gas (MMcf)	Oil (MBbl)
Colorado-Sand Wash Basin	28,011	114	12,624	53	11,693	51
Wyoming:						
Powder River Basin	325,966	-	414,143	-	392,950	7
Green River Basin	314,747	2,539	153,897	1,160	65,594	603
Total	668,724	2,653	580,664	1,213	470,237	661

The report for proved reserves in the Powder River Basin CBM gas and other Wyoming assets for 2003 was prepared by Netherland, Sewell & Associates, Inc, or NSAI. The reports for proved reserves in the Powder River Basin CBM gas and other Wyoming assets for 2002 and 2001 were audited by NSAI.

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 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.

Gas Gathering, Processing and Treating

At December 31, 2003, we operated a variety of gathering, processing and treating facilities, or plant operations, with approximately 10,300 miles of gathering lines, as presented on the Principal Gathering and Processing Facilities Table set forth below. These facilities are primarily located in five states and have a combined throughput capacity of approximately 2.9 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. 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. 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, Oklahoma and New Mexico. 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.

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, overall we have been successful in connecting additional reserves to more than offset the natural declines. However, 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, 2003, the estimated reserves connected to our midstream facilities totaled approximately 3.8 Tcf. This includes estimated third-party reserves connected to our facilities, which are based upon our interpretation of publicly available well and production information and are not the result of audited reserve reports prepared for us, and our connected proven reserves in the Powder River and Green River Basins.

Substantially all gas flowing through our 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 79% of our plant facilities' gross margin, or revenues at the plant less product purchases, for the month of December 2003 was under percentage-of-proceeds agreements where we are typically responsible for the marketing of the gas and NGLs. Under these agreements, we pay producers a specified percentage of the net proceeds received from the sale of the gas and the NGLs.

Approximately 14% of our plant facilities' gross margin for the month of December 2003 was under 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.

Approximately 7% of our plant facilities' gross margin for the month of December 2003 was under contracts with "keepwhole" arrangements or wellhead purchase contracts. We retain 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.

Midstream Operating Areas

Powder River Basin. Our midstream operations in the Powder River Basin are fully integrated with our upstream operations as we provide the gathering, compression and processing services for our own production. Additionally we provide the same types of services for third parties. As of December 31, 2003, 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, several gas processing facilities with a combined capacity of 146 MMcf per day, and our 13% equity interest in Fort Union Gas Gathering, L.L.C., or Fort Union.

We averaged 416 MMcf per day of CBM gathering volumes, including third-party gas, during the fourth quarter of 2003. Of that volume, approximately 106 MMcf per day was transported through our MIGC pipeline. As part of our settlement of on-going litigation with our co-developer in this area, we amended our long-term gathering contract for gas produced by our co-developer to significantly increase the area of dedication, to extend the term of the contract, and to modify the fee schedule. While this does not immediately increase our gathering volumes, we believe that we are well positioned for future growth opportunities.

We are the construction manager and field operator of the Fort Union gathering system and header. The Fort Union system 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 has a capacity of 635 MMcf per day. We have a long-term gathering agreement with Fort Union for 83 MMcf per day of this capacity at $0.14 per Mcf.

We spent approximately $10.3 million in the Powder River Basin for midstream activities during 2003. Our capital budget in the Powder River Basin for midstream activities provides for expenditures of approximately $31.6 million during 2004. 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 during 2004.

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., or Rendezvous, our Red Desert facility and our Table Rock, Wamsutter and Desert Springs gathering systems. These facilities have a combined gathering capacity of 682 MMcf per day, and in the year ended December 31, 2003, these facilities averaged throughput of 554 MMcf per day. Additionally, these systems have a combined processing capacity of 257 MMcf per day and in the year ended December 31, 2003, processed an average of 214 MMcf per day.

During 2003, we spent approximately $67.7 million in capital expenditures for midstream activities in this basin, including $37.1 million for the acquisition of several gathering systems. Our 2004 capital budget for midstream activities in this basin provides for expenditures of approximately $40.7 million. This capital budget includes approximately $39.7 million for gathering lines and installation of compression to expand the capacity of our Granger Complex, our Wamsutter gathering system and our Red Desert facility, and $1.0 million for additional contributions to Rendezvous for the expansion of its systems. 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 during 2004.

In 2001, we, together with an unrelated third-party, formed Rendezvous. Rendezvous gathers gas along the Pinedale Anticline for blending or processing at either our Granger Complex or at the third-party owned and operated Blacks Fork processing facility. Each company owns a 50% interest in Rendezvous, and we serve as field operator of its systems. An expansion of Rendezvous was completed in December 2003 bringing its capacity to approximately 275 MMcf per day and in the year ended December 31, 2003 gathered an average of 221 MMcf per day. The cost of this expansion is expected to approximate $32.0 million gross, of which our share will be approximately $16.0 million. As part of Rendezvous' expansion process, in March 2004 we shall be implementing an upgrade of our 100 MMcf per day refrigeration unit at our Granger plant at a cost of $2.8 million.

West Texas. Our primary assets in west Texas are the Midkiff/Benedum complex and the Gomez and Mitchell Puckett treating facilities. 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 the year ended December 31, 2003. Also for this period, these facilities produced an average of 212 MMcf per day of natural gas for delivery to sales markets and produced an average of 802 MGal per day of NGLs. In 2003, our capital expenditures in this area totaled approximately $7.1 million. Our capital budget in this area provides for expenditures of approximately $5.1 million during 2004. This budget includes approximately $2.7 million for additions to the gathering systems and plant facilities and approximately $2.4 million for replacing and upgrading field and plant equipment.

Oklahoma. Our primary assets in Oklahoma are the Chaney Dell and Westana systems. These facilities gather and process gas produced by third parties in the Anadarko Basin and have a combined operational capacity of 175 MMcf per day. During the year ended December 31, 2003, these facilities gathered an average of 165 MMcf per day, produced an average of 142 MMcf per day of natural gas for delivery to sales markets and produced an average of 311 MGal per day of NGLs. During 2003, our capital expenditures in this area totaled $18.2 million. Our capital budget in this area provides for expenditures of approximately $14.2 million during 2004. This budget includes approximately $11.5 million for additions to the gathering systems and plant facilities and approximately $2.7 million for replacing and upgrading field and plant equipment.

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 has a combined operational capacity of 75 MMcf per day. In 2003, these facilities gathered and processed an average of 32 MMcf per day, produced an average of 25 MMcf per day of natural gas for delivery to sales markets and produced 61 MGal per day of NGLs. During 2003, our capital expenditures in this area totaled $1.0 million. Our capital budget in this area provides for expenditures of approximately $1.1 million during 2004. This budget includes approximately $900,000 for additions to the gathering systems and plant facilities and approximately $200,000 for replacing and upgrading field and plant equipment.

Principal Gathering and Processing Facilities Table. The following table provides information concerning our principal gathering, processing and treating facilities at December 31, 2003.

Facilities (1)	Year Placed In Service	Gas Gathering System Miles (2)	Gas Throughput Capacity (MMcf/D) (3)	Average for the Year Ended December 31, 2003: Gas Throughput (MMcf/D) (4)	Gas Production (MMcf/D) (5)	NGL Production (MGal/D) (5)
Texas						
Gomez Treating (6)	1971	389	280	92	83	-
Midkiff/Benedum	1949	2,249	165	138	89	801
Mitchell Puckett Treating (6)	1972	93	120	61	40	1
Wyoming						
Coal Bed Methane Gathering	1990	1,323	525	416	200	-
Desert Springs Gathering (10)	1979	65	10	6	6	15
Fort Union Gas Gathering	1999	167	635	487	487	-
Granger (7)(8)(9)	1987	555	235	226	150	306
Hilight Complex (7)	1969	626	124	16	11	53
Kitty/Amos Draw (7)	1969	314	17	6	4	27
Lincoln Road (9)	1988	149	50	36	24	12
Newcastle (7)	1981	146	5	3	2	20
Red Desert (7)	1979	111	42	13	11	22
Rendezvous	2001	238	275	221	221	-
Reno Junction (8)	1991	-	-	-	-	105
Table Rock Gathering (10)	1979	101	20	14	14	-
Wamsutter Gathering (10)	1979	230	50	38	38	4
Wind River Gathering (10)	1979	109	80	47	47	-
Oklahoma						
Chaney Dell/Westana	1966	3,205	175	165	142	311
New Mexico						
San Juan River (6)	1955	140	60	29	23	45
Utah						
Four Corners Gathering	1988	104	15	3	2	16
Total		10,314	2,883	2,017	1,594	1,738

(1) Our interest in all facilities is 100% except for Midkiff/Benedum (73%); Newcastle (50%); Fort Union gathering system (13%) and Rendezvous (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 are as of December 31, 2003.

(3) Gas throughput capacity is as of December 31, 2003 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.

(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) NGL production includes conversion of third-party feedstock to iso-butane.

(9) Lincoln Road is operated on an intermittent basis to process excess gas from the Granger system.

(10) These facilities were acquired on February 1, 2003.

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, 1999, involving assets other than those, which were previously discussed, are:

Acquisition and Disposition of Various Wyoming Gathering Systems. Effective February 1, 2003, we acquired several 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. Several of the systems located in the Powder River and Wind River basins did not integrate directly into our existing systems, and accordingly we sold these systems in the third and fourth quarters of 2003.

Toca Processing Facility. In 2002, we sold our Toca processing facility in Louisiana. The sale price was $32.2 million, and resulted in a pre-tax loss of approximately $230,000. The sale included a natural gas processing plant with a capacity of 160 million cubic feet per day and a fractionator that could 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 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.

Arkoma. In August 2001, 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 2001, 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 2001, we sold all 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 2001.

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 2001. 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 storage 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.

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, or 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 the year ended

December 31, 2003, MIGC transported an average of 159 MMcf per day. It is anticipated that MIGC will continue to operate around that level in 2004 as well. 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 five years and the fees charged averaged $0.33 per Mcf in 2003. MGTC provides transportation and gas sales to various cities in Wyoming at rates that are subject to the approval of the Wyoming Public Service Commission.

The FERC has implemented changes over the past several years to restrict transactions between regulated pipelines and affiliated companies. In addition, in November 2003, the FERC issued a notice of rulemaking limiting the use of affiliates' employees in the operation of regulated entities. We submitted a plan of compliance with the notice in February 2004 and will be in compliance with the notice by June 1, 2004. In accordance with this plan, we will add several employees to both MIGC and MGTC.

The following table provides information concerning our principal transportation assets at December 31, 2003.

			Average for the Year Ended December 31, 2003	
Transportation Facilities (1)	Year Placed In Service	Transportation Miles (2)	Pipeline Capacity (MMcf/D) (2)	Gas Throughput (MMcf/D) (3)
MIGC (4)	1970	245	130	159
MGTC (5)	1963	252	18	6
Total		497	148	165

(1) Our interest in both facilities is 100%, and we operate both facilities.
(2) Transportation miles and pipeline capacity are as of December 31, 2003. Pipeline capacity represents certificated capacity at the Powder River junction only and does not include interruptible capacity or capacity at other delivery points.
(3) Aggregate volumes transported by a pipeline.
(4) MIGC is an interstate pipeline located in Wyoming and is regulated by the FERC.
(5) MGTC is a public utility located in Wyoming and is regulated by the Wyoming Public Service Commission.

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. 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.

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. Historically, the gas produced in the Rocky Mountain region has traded at a substantial discount to the Mid-Continent and west coast areas as a result of limited pipeline capacity from the region. During 2003, additional pipeline capacity out of the Rocky Mountain region went into service. This pipeline expansion contributed to a reduction in the price difference between the Rocky Mountain region and Mid-Continent market center. We expect this additional pipeline capacity to continue to have an ongoing impact on the price differences between the Rocky Mountain and Mid-Continent regions.

For the year ended December 31, 2003, our total gas sales volumes averaged 1.4 Bcf per day, of which 485 MMcf per day was produced at our plants or from our producing properties. This volume of sales is an approximate 31% decrease as compared to 2002. In general, we reduced our sales volume due to price volatility and credit concerns with many counterparties in the energy industry. The marketing of products purchased from third-parties typically results in low profit margins relative to the sales price. We sell gas under agreements with varying terms and conditions in order to match seasonal and other changes in demand. As of December 31, 2003, the weighted average duration of our sales contracts was 14 months.

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. 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, 2003, we sold gas to approximately 266 end-users, pipelines, LDCs and other customers. No single customer accounted for more than approximately 6% of our consolidated revenues from the sale of gas, or 5% of total consolidated revenue, for the year ended December 31, 2003.

Price Reporting to Gas Trade Publications. In the third quarter of 2003,we learned that several employees in our marketing department furnished inaccurate information regarding natural gas transactions to energy publications, which compile and report energy index prices. We discovered the inaccuracies during a review of our marketing activities, which is being conducted in response to a subpoena issued by the Commodity Futures Trading Commission, or CFTC. These employees have identified inaccuracies associated with reporting of natural gas transactions primarily related to points in Texas. Our review of this and other regions is continuing as we respond to the CFTC subpoena. We have discontinued the practice of reporting pricing information to the industry publications. See further discussion in "Note 8 – Commitments and Contingencies" to the Consolidated Financial Statements.

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, 2003, NGL sales averaged 1,635 MGal per day, of which 1,355 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. Further, consumers use propane for home heating, transportation and agricultural applications. Price, seasonality and the economy primarily affect the demand for NGLs.

We sell NGLs under agreements with varying terms and conditions in order to match seasonal and other changes in demand. At December 31, 2003, the terms of our sales contracts range from one month to three years. The marketing of products purchased from third-parties typically results in low profit margins relative to the sales price. As in the case of natural gas, we continually monitor and review the credit exposure to our NGL marketing counterparties.

During the year ended December 31, 2003, we sold NGLs to 85 customers including end-users, fractionators, chemical companies and others. Two customers accounted for approximately 49% of our consolidated revenues from the sale of NGLs, or 6% of total consolidated revenue, for the year ended December 31, 2003. One of these customers is a large integrated energy company and the other is a large petrochemical company. We also derive revenues from contractual marketing fees charged to some producers for NGL marketing services. For the year ended December 31, 2003, these fees were less than 1% of our consolidated revenues.

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. Gains and losses on any accompanying financial transactions are recorded net. Additionally, for our marketing activities we utilize mark-to-market accounting. As discussed above, 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 specialists in environmental engineering, safety and regulatory compliance to monitor environmental and safety compliance at our facilities. In addition, the environmental engineers and safety specialists perform in-house audits of our existing facilities to ensure on-going compliance. 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 in February 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 have provided our remediation plan to them. All of the underground facilities that were out of compliance have been removed and in addition, all but three of the sites have been completely remediated. These remaining three sites are currently under going remediation according to the plan approved by the WYOGCC. The seller of these assets established a $1.5 million escrow account to cover the costs of remediation. To date, actual expenditures have been less than $1.0 million, and we believe that total remediation costs will be less than the escrow amount.

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 2003, 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 $1.2 million. The new spill prevention plans must be in place for covered assets by August 2004. All modifications called for in those plans must be in place by February 2005.

We are in the process of voluntarily cleaning up substances at several of the 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 $4.0 million for the year ended December 31, 2003, including approximately $763,000 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 adverse 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 in exploration and production 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 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 some 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, results of operations or cashflows. 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, 2003, we employed 655 full-time employees, of which 385 were 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, 2003.

PART II

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

As of March 3, 2004, there were 34,182,837 shares of common stock outstanding held by 194 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
2003		
Fourth Quarter	$ 47.50	$ 38.40
Third Quarter	40.05	36.39
Second Quarter	41.65	31.92
First Quarter	37.50	30.56
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

We paid annual dividends on our common stock aggregating $0.20 per share during the years ended December 31, 2003 and 2002. We have declared a dividend of $0.05 per share of common stock for the quarter ending March 31, 2004 to holders of record as of that date. 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, 2003, availability under this covenant was approximately $76.8 million.

Equity Compensation Plan Information

The following table summarizes our equity compensation plans under which securities may be issued as of December 31, 2003. 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 per share 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	1,413,575	$ 33.85	641,924
Equity compensation plans not approved by security holders	308,350	$ 24.48	-
Total	1,721,925	$ 32.17	641,924

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 the 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 of 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. This option plan will terminate on the earlier of October 15, 2010 or the date on which all options granted under the plan have been exercised in full.

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 2003. The data for the three years ended December 31, 2003, 2002 and 2001 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, 2000 and 1999 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,				
	2003	2002	2001	2000	1999
	(000s, except per share amounts and operating data)				
Statement of Operations:					
Revenues	$ 2,874,010	$ 2,489,698	$ 3,353,162	$ 3,280,091	$ 1,909,288
Gross profit (a)	210,430	144,430	200,780	149,155	67,289
Income (loss) before income taxes	144,536	80,703	152,126	88,673	(26,919)(b)
Provision (benefit) for income taxes	53,593	30,114	56,489	32,565	(9,795)
Income (loss) before cumulative effect of change in accounting principle	90,943	50,589	95,637	56,108	(17,124)(b)
Cumulative effect of change in accounting principle	(6,724)(c)	-	-	-	-
Net income (loss)	84,219	50,589	95,637	56,108	(17,124)(b)
Net income per share of common stock before cumulative effect of change in accounting principle	2.53	1.26	2.59	1.42	(.86)
Earnings (loss) per share of common stock	2.33	1.26	2.59	1.42	(.86)
Earnings (loss) per share of common stock - assuming dilution	2.26	1.23	2.48	1.39	(.86)
Other Financial Data:					
Net cash provided by operating activities	$ 248,732	$ 131,136	$ 153,267	$ 116,262	$ 95,184
Net cash provided by (used in) investing activities	(197,085)	(105,772)	(131,657)	(82,039)	67,284
Net cash provided by (used in) financing activities	(32,843)	(28,084)	(24,505)	(35,358)	(152,806)
Capital expenditures	203,068	140,637	169,751	108,536	80,089
Balance Sheet Data (at year end):					
Total assets	$ 1,460,524	$ 1,302,144	$ 1,267,942	$ 1,431,422	$ 1,049,486
Long-term debt	339,000	359,933	366,667	358,700	378,250
Stockholders' equity	562,509	483,068	473,352	391,534	349,743
Dividends on preferred stock	6,841	9,198	11,167	10,416	10,439
Dividends on common stock	6,684	6,603	6,524	6,448	6,426
Dividends per share of common stock	.20	.20	.20	.20	.20
Operating Data:					
Average gas sales (MMcf/D)	1,362	1,988	1,961	1,835	1,900
Average NGL sales (MGal/D)	1,635	2,010	2,347	3,085	2,885
Average gas volumes gathered (MMcf/D)	1,343	1,163	1,161	1,248	1,168
Facility capacity (MMcf/D)	2,883	2,581	2,574	2,374	2,485
Average gas prices ($/Mcf)	$ 4.94	$ 2.92	$ 3.97	$ 3.90	$ 2.17
Average NGL prices ($/Gal)	$ .58	$ .42	$ .49	$ .52	$ .33

(a) Excludes selling and administrative, interest expense, income tax expense, expenses for the impairment of property and equipment, (gains) or losses on sales of assets, and any charges for the early extinguishment of debt. See further discussion in notes (b) and (c).

(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, for the year ended December 31, 1999.

(c) We recognized an after-tax loss on the adoption of SFAS No. 143,"Accounting for Asset Retirement Obligations".

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, 2003, 2002 and 2001. Certain prior year amounts have been reclassified to conform to the presentation used in 2003. 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.

Company Overview

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 Greater Green River Basins in Wyoming and Colorado and our midstream operations in west Texas, Oklahoma and New Mexico. Our long-term business plan is to increase stockholder value by: (i) doubling proven reserves and equity production of natural gas from the levels achieved in 2001 over a five year period; (ii) meeting or exceeding throughput projections in our midstream operations; and (iii) optimizing annual returns.

Industry and Company Overview— In North America, our industry has experienced several consecutive years of declining natural gas production. Most of the major gas producing areas, such as the Gulf of Mexico, are mature and are in production decline. We are concentrating our efforts in the Rocky Mountain gas producing basins where there are estimated to be large quantities of undeveloped gas. The U.S. government largely retains the mineral rights to these undeveloped reserves; accordingly, the development and production of these reserves require permits from several governmental agencies including the BLM. We are well positioned for future production growth with a large inventory of undeveloped drilling locations in the Powder River and Greater Green River Basins to meet the growing demand for clean burning natural gas. In addition, our experience and technical expertise position us to acquire new opportunities to develop natural gas in the Rocky Mountain region. Our challenges will be to accomplish these goals with the difficulties encountered by the industry in obtaining the necessary permits from the BLM. We believe that our technical expertise in developing environmentally responsible solutions to the problems encountered in the development of gas reserves will be a competitive advantage in overcoming these challenges.

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. Our producing properties are primarily located in the Powder River and Green River Basins of Wyoming. These plays are low-risk, long-lived development projects. These provide us with the opportunity to steadily increase our production volume at low operating and finding and development costs. In 2003 our production grew 10% compared to 2002 levels and far exceeded the industry average for 2002 of a three percent decline in production. Our 2003 production level represented a 47% increase towards meeting our goal of doubling our equity production of natural gas. Also benefiting us in 2003 were higher prices received for natural gas. As a result operating income in this segment increased by 53% to $113.5 million in the year ended December 31, 2003 compared to 2002. At December 31, 2003, we had a total of 685 Bcfe of proved natural gas reserves in our various operating areas. Our business strategy is to double our proven reserves from those in place at December 31, 2001 by the end of 2006. At December 31, 2003, we are 44% towards meeting our goal of doubling proved reserves.

We are also actively seeking to add additional upstream core projects that are focused on Rocky Mountain natural gas. We will utilize our expertise in exploration and low-risk development of tight-gas sands, coal bed methane and fractured shale plays to evaluate acquisitions of either additional leaseholds, proven and undeveloped reserves or companies with operations focused in the Rockies. Toward this goal, we have acquired the drilling rights on approximately 340,000 net acres, in the northeastern area of the Denver-Julesburg Basin in northeast Colorado and southwest Nebraska.

Gathering, Processing and Treating—Our core operations are in well-established areas such as the Permian, Anadarko, Powder River, Greater Green River, and San Juan Basins. We connect natural gas from gas and oil wells to our gathering systems for delivery to our processing or treating plants under long-term contracts. 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. We believe that our low cost of operations, our high on-line time, and our safety records are key elements in our ability to compete effectively and provide service to our customers. Our expertise in gathering, processing and treating operations can enhance the economics of developing new upstream projects.

This segment of our operations has provided a stream of operating profit that is available for reinvestment into other projects or other segments of our business. In 2003, we realized operating profit from this segment of $126.6 million, which is a 35% increase from 2002. This segment benefited from significantly higher product prices in 2003 compared 2002 and from increased drilling activity by third-party producers behind our facilities. Overall throughput in our facilities during 2003 increased 13% from 2002 and averaged a total of 1.3 Bcf per day.

Transportation— In the Powder River Basin, we own one interstate pipeline, MIGC, and one intrastate pipeline, MGTC, which transport natural gas for producers and energy marketers under fee schedules regulated by state or federal agencies. In 2003, we realized operating profit from this segment of $11.6 million, which is a 29% decrease from 2002. The decrease in profit in this segment is due to lower interruptible transportation volume in 2003 as more gas was transported out the basin through other pipelines.

Marketing—Our gas marketing segment is an outgrowth of our gas processing and upstream activities. One of the primary goals of our gas marketing operations is 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 NGLs and through the use of firm transportation capacity. We also buy and sell natural gas and NGLs in the wholesale market in the United States and in Canada. These third-party sales, our 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. In order to protect the profitability of this segment, we continually monitor and review credit exposure to our marketing counterparties. During 2003, we experienced no uncollectible accounts.

In 2003, we realized operating profit from this segment of $31.4 million, which is a 14% decrease from 2002. The decrease in operating profit is primarily due to lower profitability on transactions associated with our firm transportation capacity from the Rocky Mountain region to the Mid-Continent. Our firm transportation allows us to purchase gas in the Rocky Mountain region for resale in the higher priced Mid-Continent markets. New transportation capacity added in 2003 out of the Rocky Mountain region has resulted in a decrease in the difference between the prices for natural gas received in this region compared to the prices received in the Mid-Continent marketing area.

Results of Operations

Year ended December 31, 2003 compared to year ended December 31, 2002
(000s, except per share amounts and operating data)

	Year Ended December 31, 2003	Year Ended December 31, 2002	Percent Change
Financial results:			
Revenues	$ 2,874,010	$ 2,489,698	15
Gross profit	210,430	144,430	46
Net income	84,219	50,589	66
Earnings per share of common stock	2.33	1.26	85
Earnings per share of common stock - diluted	2.26	1.23	84
Net cash provided by operating activities	248,732	131,136	90
Net cash (used in) investing activities	(197,085)	(105,772)	86
Net cash (used in) financing activities	(32,843)	(28,084)	17
Operating data:			
Average gas sales (MMcf/D)	1,362	1,988	(31)
Average NGL sales (MGal/D)	1,635	2,010	(19)
Average gas prices ($/Mcf)	$ 4.94	$ 2.92	69
Average NGL prices ($/Gal)	$ .58	$ .42	38

Net income increased $33.6 million for the year ended December 31, 2003 compared to 2002. The increase in net income was primarily attributable to a significant increase in gas and NGL prices in 2003 compared to last year. This increase in prices was supplemented by increased equity production from the Powder River Basin CBM project and the Green River Basin. Partially offsetting the increase in net income in the year ended December 31, 2003 was a $6.7 million after-tax loss from the cumulative effect of a change in accounting principle from the adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations" on January 1, 2003.

Revenues from the sale of gas increased $344.3 million to $2,463.0 million for the year ended December 31, 2003 compared to 2002. This increase was primarily due to an increase in product prices, which more than offset a decrease in sales volume in 2003. Average gas prices realized by us increased $2.02 per Mcf to $4.94 per Mcf for the year ended December 31, 2003 compared to 2002. Included in the calculation of the realized gas price were approximately $23.9 million of losses recognized in the year ended December 31, 2003 related to futures positions on equity gas volumes. We have entered into additional futures positions for approximately half of our equity gas for 2004. See further discussion in "Item 3. Quantitative and Qualitative Disclosures About Market Risk." Average gas sales volumes decreased 626 MMcf per day to 1,362 MMcf per day for the year ended December 31, 2003 compared to 2002. This decrease was due to a reduction in third party sales volume resulting from the increase in product prices and an intentional effort to reduce related credit exposure.

Revenues from the sale of NGLs increased approximately $36.6 million to $346.1 million for the year ended December 31, 2003 compared to 2002. This increase is primarily due to a significant increase in product prices, which was partially offset by a reduction in third-party sales volumes. Average NGL prices realized by us increased $0.16 per gallon to $0.58 per gallon for the year ended December 31, 2003 compared to 2002. Included in the calculation of the realized NGL price were approximately $11.4 million of losses recognized in the year ended December 31, 2003 related to futures positions on equity NGL volumes. We have entered into additional futures positions for approximately half of our equity NGL production for 2004. See further discussion in "Item 3. Quantitative and Qualitative Disclosures About Market Risk." Average NGL sales volumes decreased 375 MGal per day to 1,635 MGal per day for the year ended December 31, 2003 compared to 2002.

Product purchases increased by $299.3 million for the year ended December 31, 2003 compared to 2002 as a result of the significant increase in commodity prices. Overall, combined product purchases as a percentage of sales of all products remained relatively constant at approximately 89% for both 2003 and 2002.

Plant and transportation operating expense increased by $6.8 million for the year ended December 31, 2003 compared to 2002. The increase was primarily due to increased throughput at our facilities, the acquisition of several gathering systems in the first quarter of 2003 and additional leased compression in the Powder River Basin coal bed development. Also contributing to this increase were the fees paid to other companies, primarily Rendezvous, for gas gathering services. Rendezvous is a 50%-owned entity that delivers gas to our Granger Complex. Rendezvous is accounted for under the equity method, and our share of its gathering revenues is reflected in Earnings from equity investments.

Oil and gas exploration and production expenses increased by $18.2 million for the year ended December 31, 2003 compared to 2002. In our operating areas, the significant increase in residue gas prices in 2003 resulted in substantially higher severance tax expenses. Overall, lease-operating expense, or LOE, for the year ended December 31, 2003 increased by approximately $0.04 per Mcfe compared to 2002 and averaged $0.46 per Mcfe. The increase in lease-operating expense per Mcfe is primarily due to unsuccessful well expenses of $1.8 million in 2003.

Depreciation, depletion and amortization decreased by $3.1 million for the year ended December 31, 2003 as compared to 2002. This decrease was the result of revisions to the operating lives, and salvage values, of our operating assets partially offset by increased production in the Powder River Basin and additional depreciation in 2003 from new projects. The revisions to the operating lives and salvage values of our operating assets were the result of analysis performed in connection with the adoption of SFAS No. 143 on January 1, 2003 and were treated as a revision of an estimate and are accounted for on a prospective basis.

Selling and administrative expenses increased by approximately $4.6 million in the year ended December 31, 2003 as compared to 2002. This increase was the result of higher compensation expenses due to an increased employee count in 2003 resulting from our growing exploration and production operations, and a modification in 2003 to our incentive compensation plan to pay this compensation on a current basis as opposed to a vesting schedule used in prior years. Also contributing to the increase were higher professional fees resulting from litigation concluded in 2003 and our ongoing research associated with the CFTC investigation of our price reporting to trade publications. Partially offsetting these increases were fewer charges for doubtful accounts in 2003 as compared to 2002.

In 2003, in order to properly align our hedged volumes of natural gas to our forecasted equity production, we discontinued hedge treatment on financial instruments for 10 MMcf per day of natural gas and 50,000 Barrels per month of ethane. As a result, a pre-tax loss of $2.8 million was reclassified into earnings from Accumulated other comprehensive income.

Cash Flow Information

Cash flows from operating activities increased by $117.6 million in 2003 compared to 2002. This increase was primarily due to an increase in net income in 2003 compared to the prior year and the timing of cash receipts and payables.

Cash flows used in investing activities increased by $91.3 million in 2003 compared to 2002. This increase was primarily due to a higher level of capital expenditures.

Cash flows used in financing activities increased by $4.8 million in 2003 compared to 2002. This increase was due to increased cash flows from operating activities, which was used to reduce our long-term debt.

Other Information

Acquisition and Disposition of Gathering Systems. Effective February 1, 2003, we acquired several 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. Several of the systems located in the Powder River and Wind River did not integrate directly into our existing systems, and accordingly these systems were sold. During the year ended December 31, 2003, the income, if any, generated by the assets sold was immaterial for separate presentation as a discontinued operation.

Acquisition of Sand Wash Properties. In August 2003, through the acquisition of the stock of a private corporation for $12.9 million, we acquired additional reserves, production and acreage in this area. The assets of this private entity consisted primarily of the remaining interests in various Sand Wash properties that we operate. This acquisition included approximately 11 billion cubic feet equivalent, or Bcfe, of proved reserves, 2.1 MMcfe per day of production and approximately 11,000 net acres under lease.

Segment Information

Gas Gathering, Processing and Treating. The Gas Gathering, Processing and Treating segment realized segment-operating profit of $126.6 million for the year ended December 31, 2003 as compared to $93.6 million in 2002. The increase in operating profit in this segment in 2003 is primarily due to higher commodity prices, increased gathering volumes and the acquisition of several gathering systems in February 2003.

Exploration and Production. The Exploration and Production segment realized segment-operating profit of $113.5 million for the year ended December 31, 2003 compared to $74.1 million in 2002. The increase in operating profit in this segment in 2003 was primarily due to substantially higher natural gas prices and production volume growth from the Powder River Basin CBM area and the Pinedale Anticline.

Marketing. The Marketing segment realized segment-operating profit of $31.4 million for the year ended December 31, 2003 compared to $36.4 million in 2002.

The decrease in the marketing margin is primarily due to transactions associated with our firm transportation capacity from the Rocky Mountain region to the Mid-Continent. Our firm transportation allows us to purchase gas in the Rocky Mountain region for resale in the higher priced Mid-Continent markets. In the second quarter of 2003, additional transportation capacity out of the Rocky Mountain region became operational, which reduced the price difference between the two regions. We expect that the reduced margins will continue in future periods. There is no assurance that the margins we realized on the sale of gas in 2003 will continue in the future, or that we will continue to originate the same amount of transactions in future years.

Transportation. The Transportation segment realized segment-operating profit of $11.6 million for the year ended December 31, 2003 compared to $16.3 million in 2002. The transportation segment includes the results from the MIGC and MGTC pipelines in the Powder River Basin. The decrease in profit in this segment is due to lower interruptible transportation volume in 2003 as more gas was transported out the basin through other pipelines.

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)
Earnings per share of common stock	1.26	2.59	(51)
Earnings per share of common stock - diluted	1.23	2.48	(50)
Net cash provided by operating activities	131,136	153,267	(14)
Net cash (used in) investing activities	(105,772)	(131,657)	(20)
Net cash (used in) financing activities	(28,084)	(24,505)	15
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 was 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 CBM development.

Revenues from the sale of gas decreased $747.6 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 $28.1 million of gains recognized in the year ended December 31, 2002 related to futures positions on equity gas volumes. Average gas sales volumes increased minimally to 1,988 MMcf per day in the year ended December 31, 2002 compared to 2001.

Revenues from the sale of NGLs decreased approximately $114.6 million to $309.5 million in the year ended December 31, 2002 compared to 2001. This decrease was 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 $8.2 million of losses recognized in the year ended December 31, 2002 related to futures positions on equity NGL volumes. 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 91% 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.

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 compared 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 represented increases of $0.06 per Mcf and $0.03 per Mcf from the comparable periods in 2001, respectively. The increases were 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 CBM 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.

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

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 $230,000. 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. 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 February 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.

Segment Information

Gas Gathering, Processing and Treating. The Gas Gathering, Processing and Treating segment realized segment-operating profit of $93.6 million for the year ended December 31, 2002 as compared to $134.3 million in 2001. The decrease in operating profit in this segment in 2002 is primarily due to lower commodity prices, partially offset by gains in equity hedges.

Exploration and Production. The Exploration and Production segment realized segment-operating profit of $74.1 million for the year ended December 31, 2002 compared to $64.2 million in 2001. The increase in operating profit in this segment in 2002 was primarily due to production volume growth from the Powder River Basin CBM area and the Pinedale Anticline, substantially offset by lower commodity prices.

Marketing. The Marketing segment realized segment-operating profit of $36.4 million for the year ended December 31, 2002 compared to $47.4 million in 2001. The margins earned from the sale of third-party natural 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.

Transportation. The Transportation segment realized segment-operating profit of $16.3 million for the year ended December 31, 2002 compared to $16.3 million in 2001. The transportation segment includes the results from the MIGC and MGTC pipelines in the Powder River Basin.

Critical Accounting Estimates

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. 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. Although there are a number of areas where we use estimates, what we believe to be the most significant ones are discussed below.

Property and Equipment. Depreciation on our property and equipment 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 Reserves, Properties and Equipment. We follow the successful efforts method of accounting for oil and gas exploration and production activities. Producing properties and related equipment are depleted and depreciated by the units-of-production method based on estimated proved reserves. The units of production method is sensitive to the determination of proved reserves. To the extent the reserves are modified, the depletion determined under the units of production method will be increased or decreased on a prospective basis.

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.

Asset Retirement Obligations. We use significant judgment in estimating our future liability for asset retirement. We evaluate each asset and in some cases individual components of assets to determine and estimate the future cost and timing of retiring those assets. The estimate of the future cost is then discounted back to the present and recorded as a liability. This liability will vary based upon the probability, timing and the extent of remediation necessary to reclaim those facilities, the discount factor used in those determinations and the projected costs of the remediation. We evaluate these estimates on an ongoing basis and modify our assumptions as appropriate.

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. In accordance with SFAS No. 144 "Accounting for the Impairment or Disposal of Long Lived Assets", assets are to be evaluated at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets. Accordingly, our review is completed at the plant facility, the related group of plant facilities or the oil and gas producing field or producing coal seam 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 associated reserves. 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, production rates and the evaluation in determining asset groupings for which cash flows are largely independent of the cash flows of other assets.

In the fourth quarter of 2003, we conducted a review of our oil and gas producing properties, which included an evaluation of the geologic formations and production history for these properties. This review indicated that the cash flows from individual wells in our operating areas were not largely independent of the cash flows of other wells producing in the same field or coal seam. As a result of this review, we redefined the asset groupings to a field wide analysis for impairment for the Jonah, Pinedale and Sand Wash Basins and to a grouping of all wells drilled into related coal seams for the Powder River Basin. These asset groupings were used to determine if any impairment was necessary for the year ended December 31, 2003 and it was determined that none of these asset groups were impaired. In addition, while the Company did not recognize any impairment of our producing properties in the years ended December 31, 2002 or 2001 under the asset groupings utilized in those years, a reevaluation of those years using our new asset groups also did not result in an impairment of our producing properties.

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. A specific area 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.

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 2004. The following pronouncements have been issued but not yet adopted.

SFAS No. 141 and SFAS No. 142. SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Intangible Assets" were issued in June 2001 and became effective for us on July 1, 2001 and January 1, 2002. SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. One interpretation being considered relative to these standards is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on the Consolidated Balance Sheet. In addition, the disclosures required by SFAS No. 141 and No. 142 relative to intangibles would be included in the Notes to Consolidated Financial Statements. Historically, we have included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the Oil and gas properties and equipment, even after SFAS No. 141 and No.142 became effective.

This interpretation of SFAS No. 141 and No. 142 described above would only affect the Consolidated Balance Sheet classification of oil and gas leaseholds. Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with accounting rules for oil and gas companies provided in SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies".

At December 31, 2003, we had undeveloped leaseholds of $55.9 million that would be classified on the Consolidated Balance Sheet as "intangible undeveloped leaseholds" and developed leaseholds of $31.7 million that would be classified as "intangible developed leaseholds" if the interpretation currently being considered was applied. We will continue to classify our oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

FIN 46. In January 2003, the FASB issued Interpretation No. 46, or "FIN 46", "Consolidation of Variable Interest Entities." FIN 46 provides guidance on how to identify a variable interest entity, or 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, as amended, must be adopted at the beginning of the first quarter of 2004. We did not create any VIEs after January 31, 2003 and we are continuing to evaluate the impact of FIN 46 on any VIEs created prior to that date and will adopt this pronouncement as required.

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 additional or alternative financing sources. Product prices, hedges of equity production, 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 are all expected to have significant influences on our 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, we have been successful in developing additional reserves of natural gas and increasing our equity natural gas production. However, the overall level of drilling and production associated with our producing properties will depend upon, among other factors, the price for gas, availability of transportation capacity to market centers, the energy and environmental policy and regulation by governmental agencies, and the issuance of drilling and water disposal permits, none of which is entirely within our control. Any reduction in the levels of exploration, development and production by us or a significant reduction in natural gas prices could have a material adverse effect on our financial condition, results of operations and cash flows.

Although some of our plants have experienced natural declines in dedicated reserves, overall we have been successful in connecting additional reserves to more than offset these declines. However, the overall level of drilling associated with our plant facilities 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, the pace at which drilling permits are received, 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. 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, results of operations and cash flows.

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 and complete our current capital expenditure program. Depending on the timing and the amount of our future projects, 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 may use 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.

During 2003, we entered into an amended and restated revolving credit facility and utilized a portion of that facility to fund $43.3 million in scheduled payments on the master shelf agreement discussed below. We believe that cash provided by operating activities and amounts available under the revolving credit facility will be sufficient to meet scheduled principal repayments during 2004 of $35.0 million under the master shelf agreement and our projected preferred stock dividend requirements during 2004.

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.

Preferred Stock Redemption. During the fourth quarter of 2003, we issued two notices of redemption for a total of 1,500,000 shares of our $2.625 cumulative convertible preferred stock. The holders of these shares had the right to convert them into shares of our common stock in lieu of receiving the redemption price in cash. In total, we issued an additional 1,840,333 shares of common stock and paid $1.9 million in cash proceeds to complete these redemptions. After completing these redemptions, we have a total of 1,252,943 shares of our $2.625 cumulative convertible preferred stock outstanding and, assuming no further redemption, we would anticipate paying in 2004 a total of $3.3 million in preferred dividends.

Sources and Uses of Funds. Our sources and uses of funds for the year ended December 31, 2003 are summarized as follows (dollars in thousands):

Sources of funds:	
Borrowings under the revolving credit facility	$ 1,022,300
Borrowings under the master shelf agreement	25,000
Proceeds from the dispositions of property and equipment	5,983
Net cash provided by operating activities	248,732
Proceeds from exercise of common stock options	5,027
Total sources of funds	$ 1,307,042
Uses of funds:	
Payments related to long-term debt (including debt issue costs)	$ 1,070,094
Capital expenditures	188,318
Contributions to equity investees	14,750
Redemption of $2.625 cumulative convertible preferred stock	1,201
Preferred dividends paid	6,841
Common dividends paid	7,034
Total uses of funds	$ 1,288,238

Capital Investment Program. We currently anticipate capital expenditures in 2004 of approximately $243.5 million. The 2004 capital budget is a 20% increase over the amount expended in 2003. This increase is the result of an expected increase in drilling activity in each of our upstream areas and additional drilling activity by third party producers whose acreage is dedicated to our midstream facilities. Overall, capital expenditures in the Powder River Basin CBM development and in southwest Wyoming operations represent 42% and 40%, respectively, of the total 2004 budget. Due to drilling and regulatory uncertainties that are beyond our control, we can make no assurance that our capital budget for 2004 will not change. This budget may be increased to provide for acquisitions if approved by our board of directors.

The 2004 capital budget and our capital expenditures during the year ended December 31, 2003, which totaled approximately $203.1 million, are presented in the following table (dollars in thousands).

Type of Capital Expenditure	Amount Expended During the Year Ended December 31, 2003	2004 Capital Budget
Gathering, processing, treating and pipeline assets	$ 69.6*	$ 97.0*
Exploration and production and lease acquisition activities	73.1	135.7
Acquisition of gathering systems, which closed in February 2003	37.1	-
Acquisition of all the capital stock of a private corporation which closed in August 2003	12.9	-
Information technology and other items	4.4	3.0
Capitalized interest and overhead	6.0	7.8
Total	$ 203.1	$ 243.5

* Includes $14.4 million and $11.7 million in 2004 and 2003, respectively, for maintaining existing facilities.

Contractual Commitments and Obligations

Contractual Cash Obligations. A summary of our contractual cash obligations as of December 31, 2003 is as follows (dollars in thousands):

		Payments by Period			
Type of Obligation	Total Obligation	Due in 2004	Due in 2005 – 2006	Due in 2007 – 2008	Due Thereafter
Guarantee of Fort Union Project Financing	$ 5,547	$ 804	$ 1,795	$ 2,081	$ 867
Operating Leases	76,273	12,662	25,815	22,785	15,011
Firm Transportation Capacity and Gathering Agreements	215,524	29,262	56,437	52,372	77,453
Firm Storage Capacity Agreements	20,452	6,198	9,450	3,043	1,761
Long-term Debt	339,000	35,000	20,000	129,000	155,000
Total Contractual Cash Obligations	$ 656,796	$ 83,926	$ 113,497	$ 209,281	$ 250,092

Guarantee of Fort Union Project Financing. We own a 13% equity interest in Fort Union Gas Gathering, L.L.C., or Fort Union, and are the construction manager and field operator. Fort Union gathers and treats natural gas in the Powder River Basin in northeast Wyoming. Initial construction and any expansions of the gathering header and treating system have been project financed by Fort Union. This debt is amortizing on an annual basis and is scheduled to be fully paid in 2009. All participants in Fort Union have guaranteed Fort Union's payment of the project financing on a proportional basis, resulting in our guarantee of $5.5 million of the debt of Fort Union at December 31, 2003. Our requirement to fund under this guarantee would be reduced by the value of assets held by Fort Union. 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, 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. These leases have terms ranging from one month to ten years with return or fair market purchase options available at various times during the lease. If we were to exercise the purchase options on all the leased equipment, these purchase options would require the capital expenditure of approximately $37.0 million between 2007 and 2012.

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, 2003, we had contracts for approximately 610 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 172 MMcf per day of gas from the Rocky Mountain area to the Mid-Continent. This utilizes a total of approximately 376 MMcf per day of firm capacity on three separate pipelines. The total rate under these long-term contracts to transport this gas to the Mid-Continent from the southern Powder River Basin approximates $0.35 per Mcf. Our remaining firm capacity consists of 99 MMcf per day to markets within the Rocky Mountains and 135 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. These agreements are not reflected on our Consolidated Balance Sheet.

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 year ended December 31, 2003, 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. The fixed fees associated with our existing contracts for firm transportation capacity during 2004 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, 2003, we had contracts in place for approximately 16.3 Bcf of storage capacity at various third-party facilities. Of the total storage capacity under contract, approximately 7.7 Bcf is under contract to our Canadian subsidiary, WGR Canada, Inc., and Western guarantees the subsidiary's performance under these contracts. This subsidiary is wholly owned by us and fully consolidated in our financial statements.

The fees associated with these contracts in 2004 will average $0.53 per Mcf of annual capacity. The associated contract periods at December 31, 2003 have an average term of twenty-nine months. At December 31, 2003, we held gas in our contracted storage facilities and in imbalances of approximately 12.7 Bcf at an average cost of $4.64 per Mcf compared to 15.1 Bcf at an average cost of $2.72 per Mcf at December 31, 2002. These positions are for storage withdrawals within the next twelve months. At the time 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. These agreements for storage capacity are not reflected on our Consolidated Balance Sheet.

From time to time, we lease NGL storage space at major trading locations to facilitate the distribution of products. At December 31, 2003, we held NGLs in storage at various third-party facilities of 2,989 MGal, consisting primarily of propane and ethane, at an average cost of $0.30 per gallon compared to 2,755 MGal at an average cost of $0.25 per gallon at December 31, 2002. These agreements for storage capacity are not reflected on our Consolidated Balance Sheet.

Long-term Debt

Revolving Credit Facility. At December 31, 2003, $94.0 million was outstanding under our existing four-year, $300 million revolving credit facility. This facility matures in April 2007. Loans made under this facility are secured by a pledge of the capital stock of our significant subsidiaries. These subsidiaries also guarantee the borrowings under the facility. The facility contains a provision that requires us to secure loans under the facility with 75% of our oil and gas reserves. This provision would only be triggered in the event of a reduction to a debt rating on the revolving credit facility of Ba3 or lower by Moody's Investors Service, Inc., or Moody's, or the reduction to a debt rating on the revolving credit facility of BB- or lower by Standard & Poor's Rating Services, a division of The McGraw-Hill Companies, Inc., or S&P. This facility has been rated Ba1by Moody's and BB+ by S&P.

The borrowings under the credit facility bear interest at Eurodollar rates or a base rate, as requested by us, plus an applicable percentage based on our debt to capitalization ratio. The base rate is the agent's published prime rate. We also pay a quarterly facility fee ranging between 0.30% and 0.50%, depending on our debt to capitalization ratio. This fee is paid on the total commitment. At December 31, 2003, the interest rate payable on borrowings under this facility was approximately 2.9%.

Under the credit facility, we are subject to a number of covenants, including: maintaining a total debt to capitalization ratio of not more than 55%; maintaining a senior debt to capitalization ratio of not more than 40%; and maintaining a ratio of EBITDA, as defined in the credit facility, to interest and dividends on preferred stock over the last four quarters in excess of 3.25 to 1.0, increasing to 3.75 to 1.0 at March 31, 2004 and to 4.25 to 1.0 at March 31, 2005.

The credit facility ranks equally with borrowings under our master shelf agreement with The Prudential Insurance Company.

Master Shelf Agreement. Amounts outstanding under the master shelf agreement with The Prudential Insurance Company of America at December 31, 2003 are as indicated in the following table (dollars in thousands):

Issue Date	Amount	Interest Rate	Final Maturity	Principal Payment Schedule
October 27, 1994	$ 25,000	9.24%	October 27, 2004	single payment at maturity
July 28, 1995	40,000	7.61%	July 28, 2007	$10,000 on each of July 28, 2004 through 2007
January 17, 2003	25,000	6.36%	January 17, 2008	single payment at maturity
	$ 90,000			

Our borrowings under the master shelf agreement are secured by a pledge of the capital stock of our significant subsidiaries, some of which have also provided a guaranty of payments we owe under the facility. The master shelf requires us to secure loans under the facility with 75% of our oil and gas reserves. This provision would only be triggered in the event of a reduction to the debt rating on the revolving credit facility of Ba3 or lower by Moody's or the reduction to the debt rating on the revolving credit facility of BB- or lower by S&P.

Under our master shelf agreement, we are subject to a number of covenants, including: maintaining 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; maintaining a total debt to capitalization ratio of not more than 55% and a senior debt to capitalization ratio of not more than 40%; maintaining a quarterly test of EBITDA, as defined in the master shelf agreement, to interest for the last four quarters in excess of 3.25 to 1.0, increasing to 3.75 to 1.0 at March 31, 2004 and to 4.25 to 1.0 at March 31, 2005; and maintaining a ratio of senior debt to EBITDA of no greater than 4.0 to 1.0.

In the fourth quarter of 2003, we utilized funds available under the revolving credit facility to fund $33.3 million in scheduled payments under the master shelf agreement, and in 2004 we will make scheduled payments totaling $35.0 million on this facility. We intend to fund these repayments with funds available under the revolving credit facility.

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 tradable 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. The subordinated notes are unsecured and are guaranteed on a subordinated basis by 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. The senior subordinated notes are callable at our option, in whole or in part, at 105% of par value beginning in June 2004 and are callable at decreasing premiums thereafter. Our ability to call these notes may be restricted by the covenants under our other debt facilities.

Covenant Compliance. We were in compliance with all covenants in our debt agreements at December 31, 2003.

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 specialists in environmental engineering, safety and regulatory compliance to monitor environmental and safety compliance at our facilities. In addition, on an ongoing basis, our 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 we acquired in February 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 have provided our remediation plan to them. All of the underground facilities that were out of compliance have been removed and in addition, all but three of the sites have been completely remediated. These remaining three sites are currently under going remediation according to the plan approved by the WYOGCC. The seller of these assets established a $1.5 million escrow account to cover the costs of remediation. To date, actual expenditures have been less than $1.0 million, and we believe that total remediation costs will be less than the escrow amount.

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 2003, 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 a 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 of 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 $1.2 million. The new spill prevention plans must be in place for covered assets by August 2004. All modifications called for by those plans must be in place by February 2005.

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 $4.0 million for the year ended December 31, 2003, including approximately $763,000 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 adverse 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 and net income in relation to those anticipated by our operating budget. The second goal is to manage price risk related to our 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 also use financial instruments to reduce 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 counterparties, consisting primarily of investment banks, financial institutions and other natural gas companies. We conduct credit reviews of all of our OTC counterparties 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 OTC exposures. OTC exposure is marked-to-market daily for the credit review process. Our exposure to OTC credit risk is reduced by our ability to require a margin deposit from our counterparties based upon the mark-to-market value of their net exposure. We are also subject to margin deposit requirements under these same agreements and under margin deposit requirements for our NYMEX transactions. At December 31, 2003, we had $5.7 million of margin deposits outstanding.

We continually monitor and review the credit exposure to our marketing counterparties. 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 netting agreements similar to those that we utilize 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.

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 counterparties 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 January 31, 2004, we have hedged approximately 49% of our projected 2004 equity natural gas volumes and approximately 55% of our estimated equity production of crude oil, condensate, and NGLs. All of 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. Realized gains or losses on these cash flow hedges are recognized in the Consolidated Statement of Operations through Product purchases when the hedged transactions occur.

To qualify as cash flow hedges, the hedge instruments must be designated as cash flow hedges and changes in their fair value must be highly correlated 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 the price of the commodity and, if applicable, 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 natural gasoline, butane and condensate. Our hedges are tested for effectiveness at inception and on a quarterly basis thereafter. We use regression analysis based on a five-year period of time for this test. Based on the results of the regression analysis, these hedges are expected to continue to be "highly effective" under SFAS No. 133 in the future. Gains or losses from the ineffective portions of changes in the fair value of cash flow hedges are recognized currently in earnings through Price risk management activities. During the year ended December 31, 2003, we recognized a loss of $110,000 from the ineffective portions of our hedges.

Outstanding Equity Hedge Positions and the Associated Basis for 2004. The following table details our hedge positions as of January 31, 2004. 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 $1.2 million. There is no associated cost for the natural gas hedges.

Product	Quantity and Settle Price	Hedge of Basis Differential
Natural gas	70,000 MMBtu per day with a minimum price of $4.00 and a maximum price ranging from $6.50 to $9.45 per MMBtu (average of $7.81 per MMBtu.)	Mid-Continent – 55,000 MMBtu per day with an average basis price of ($0.27) per MMBtu. Permian – 5,000 MMBtu per day with an average basis price of ($0.34) per MMBtu. Rocky Mountain – 10,000 MMBtu per day with an average basis price of ($0.74) per MMBtu.
Crude, Condensate, Natural Gasoline	50,000 Barrels per month with a minimum price of $22.00 per barrel and a maximum price of $30.08 per barrel.	Not Applicable
Butanes	50,000 Barrels per month. Floor at $22.00 per barrel. (Crude oil is used as surrogate for butanes.)	Not Applicable
Propane	90,000 Barrels per month with minimum and maximum price of $0.42 per gallon and $0.56 per gallon, respectively.	Not Applicable
Ethane	50,000 Barrels per month. Floor at $0.305 per gallon.	Not Applicable

Account balances related to equity and transportation hedging transactions at December 31, 2003 were $1.7 million in Current assets from price risk management activities, $5.2 million in Current Liabilities from price risk management activities, ($1.3) million in Deferred income taxes payable, net, and a $2.3 million after-tax unrealized loss in Accumulated other comprehensive income, a component of Stockholders' Equity. Based on prices as of December 31, 2003, approximately $2.3 million of losses in Accumulated other comprehensive income will be reclassified to earnings in 2004.

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. As of December 31, 2003, our VaR position for natural gas and liquid marketing portfolios was $385,000 and the average for all of 2003 was $496,000. This figure includes the risk related to our entire marketing portfolio of natural gas and NGL financial instruments and the related underlying physical transactions. We also measure market risk by sensitivity valuations. As of December 31, 2003, an increase in natural gas prices of $1.00 per MMbtu would lead to an increase in the fair value of our marketing portfolio of $135,000 and an increase in crude oil prices of $5.00 per barrel would lead to an increase in the fair value of our marketing portfolio of $600,000. 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, 2002 to December 31, 2003 is as follows (dollars in thousands):

Fair value of contracts outstanding at December 31, 2002	$ 63
Decrease in value due to change in price	(27,760)
Increase in value due to new contracts entered into during the period	23,817
Losses realized during the period from existing and new contracts	10,587
Changes in fair value attributable to changes in valuation techniques	-
Fair value of contracts outstanding at December 31, 2003	$ 6,707

A summary of our outstanding derivative positions at December 31, 2003 is as follows (dollars in thousands):

Source of Fair Value	Fair Value of Contracts at December 31, 2003				
	Total Fair Value	Maturing In 2004	Maturing In 2005-2006	Maturing In 2007-2008	Maturing Thereafter
Exchange published prices	$ 381	$ (4)	$ 385	-	-
Other actively quoted prices (1)	7,978	8,203	(225)	-	-
Other valuation methods (2)	(1,652)	(1,654)	2	-	-
Total fair value	$ 6,707	$ 6,545	$ 162	-	-

(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, 2003, the net notional value of such contracts was approximately $24.3 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, 2003 and 2002 and for each of the three years in the period ended December 31, 2003:

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 auditors, audits the Company's financial statements. Their report states that they have conducted their audit in accordance with generally accepted auditing standards. Those standards require that the independent auditors consider internal control in planning and performing their audit, and to determine the nature, timing and extent of tests to be performed.

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 auditors to review how each is carrying out its responsibilities and to discuss matters concerning auditing, internal accounting control and financial reporting. The independent auditors 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 AUDITORS

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, 2003 and 2002, and the results of their cash flows and their operations for each of the three years in the period ended December 31, 2003, 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. As discussed in Note 2 to the financial statements, the Company changed its method of accounting for asset retirement obligations effective January 1, 2003 and its method of testing long-lived assets for impairment.

PricewaterhouseCoopers LLP

Denver, Colorado
March 9, 2004

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

	December 31, 2003	December 31, 2002
ASSETS		
Current assets:		
Cash and cash equivalents	$ 26,116	$ 7,312
Trade accounts receivable, net	262,509	253,587
Inventory	70,304	44,219
Assets held for sale	-	3,250
Assets from price risk management activities	17,149	34,873
Other	11,225	27,701
Total current assets	387,303	370,942
Property and equipment:		
Gas gathering, processing and transportation	1,028,176	942,147
Oil and gas properties and equipment (successful efforts method)	329,555	252,747
Construction in progress	134,751	104,033
	1,492,482	1,298,927
Less: Accumulated depreciation, depletion and amortization	(495,721)	(432,281)
Total property and equipment, net	996,761	866,646
Other assets:		
Gas purchase contracts (net of accumulated amortization of $38,937 and $37,232, respectively)	29,219	30,924
Assets from price risk management activities	1,466	406
Other	45,775	33,226
Total other assets	76,460	64,556
TOTAL ASSETS	$ 1,460,524	$ 1,302,144
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 303,186	$ 242,987
Accrued expenses	42,136	51,509
Liabilities from price risk management activities	10,603	34,811
Dividends payable	3,056	3,464
Total current liabilities	358,981	332,771
Long-term debt	339,000	359,933
Liabilities from price risk management activities	1,304	406
Other long-term liabilities	22,057	1,713
Deferred income taxes payable, net	176,673	124,253
Total liabilities	898,015	819,076
Stockholders' equity:		
Preferred Stock; 10,000,000 shares authorized:		
$2.625 cumulative convertible preferred stock, par value $.10; 2,060,000 issued ($102,817,000 aggregate liquidation preference)	206	276
Common stock, par value $.10; 100,000,000 shares authorized; 34,135,901 and 33,077,611 shares issued, respectively	3,438	3,329
Treasury stock, at cost; 25,016 common shares in treasury	(788)	(788)
Additional paid-in capital	385,019	381,066
Retained earnings	173,076	102,292
Accumulated other comprehensive income (loss)	1,558	(2,812)
Notes receivable from key employees secured by common stock	-	(295)
Total stockholders' equity	562,509	483,068
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,460,524	$ 1,302,144

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,		
	2003	2002	2001
Reconciliation of net income to net cash provided by operating activities:			
Net income	$ 84,219	$ 50,589	$ 95,637
Add income items that do not affect operating cash flows:			
Depreciation, depletion and amortization	73,906	77,005	64,162
Deferred income taxes	49,326	19,614	42,815
Distributions more than or (less than) equity income, net	1,076	(2,906)	(29)
(Gain) loss on the sale of property and equipment	(156)	948	(10,748)
Non-cash change in fair value of derivatives	(1,235)	13,788	(19,906)
Compensation expense from re-priced stock options	376	224	170
Cumulative effect of change in accounting principle	6,724	-	-
Other non-cash items, net	1,430	1,809	1,405
Adjustments to working capital to arrive at net cash provided by operating activities:			
(Increase) decrease in trade accounts receivable	(7,720)	(35,216)	313,215
(Increase) decrease in product inventory	(25,136)	7,164	(5,951)
(Increase) decrease in parts inventory	-	-	440
Decrease (increase) in other current assets	8,869	(13,329)	(4,314)
Decrease (increase) in other assets and liabilities, net	(359)	348	(1,188)
Increase (decrease) in accounts payable	60,199	(16,394)	(321,355)
(Decrease) increase in accrued expenses	(2,787)	27,492	(1,086)
Net cash provided by operating activities	248,732	131,136	153,267
Cash flows from investing activities:			
Purchases of property and equipment, including acquisitions	(188,318)	(125,600)	(163,977)
Proceeds from the disposition of property and equipment	5,983	34,865	38,094
Contributions to equity investees	(14,750)	(15,037)	(5,774)
Net cash used in investing activities	(197,085)	(105,772)	(131,657)
Cash flows from financing activities:			
Net proceeds from exercise of common stock options	5,027	6,489	5,191
Payments for the re-purchase of preferred stock	-	-	(129)
Payments for the redemption of preferred stock	(1,201)	(12,607)	(20,591)
Borrowings under long-term debt	25,000	-	-
Payments on long-term debt	(43,333)	(8,333)	(33,333)
Borrowings under revolving credit facility	1,022,300	994,545	569,630
Payments on revolving credit facility	(1,024,900)	(992,945)	(528,330)
Debt issue costs paid	(1,861)	(126)	(97)
Dividends paid	(13,875)	(15,107)	(16,846)
Net cash used in financing activities	(32,843)	(28,084)	(24,505)
Net increase (decrease) in cash and cash equivalents	18,804	(2,720)	(2,895)
Cash and cash equivalents at beginning of year	7,312	10,032	12,927
Cash and cash equivalents at end of year	$ 26,116	$ 7,312	$ 10,032

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,		
	2003	2002	2001
Revenues:			
Sale of gas	$ 2,463,016	$ 2,118,748	$ 2,866,424
Sale of natural gas liquids	346,108	309,513	424,115
Gathering, processing and transportation revenue	83,672	65,601	55,398
Price risk management activities	(21,385)	(8,884)	2,546
Other	2,599	4,720	4,679
Total revenues	2,874,010	2,489,698	3,353,162
Costs and expenses:			
Product purchases	2,456,441	2,157,179	2,986,950
Plant and transportation operating expense	88,344	81,530	75,533
Oil and gas exploration and production costs	52,245	34,007	27,527
Depreciation, depletion and amortization	73,906	77,005	64,162
Selling and administrative expense	40,423	35,828	34,272
(Gain) loss on sale of assets	(156)	948	(10,748)
Earnings from equity investments	(7,356)	(4,453)	(1,790)
Interest expense	25,627	26,951	25,130
Total costs and expenses	2,729,474	2,408,995	3,201,036
Income before income taxes	144,536	80,703	152,126
Provision for income taxes:			
Current	4,267	10,500	13,674
Deferred	49,326	19,614	42,815
Total provision for income taxes	53,593	30,114	56,489
Income before cumulative effect of change in accounting principle	90,943	50,589	95,637
Cumulative effect of change in accounting principle, net of tax benefit of $3,967	(6,724)	-	-
Net income	$ 84,219	$ 50,589	$ 95,637
Preferred stock requirements	(6,841)	(9,198)	(11,167)
Income attributable to common stock	$ 77,378	$ 41,391	$ 84,470
Net income per share of common stock before cumulative effect of change in accounting principle	$ 2.53	$ 1.26	$ 2.59
Cumulative effect of change in accounting principle per share of common stock, net of tax	$ .20	$ -	$ -
Earnings per share of common stock	$ 2.33	$ 1.26	$ 2.59
Weighted average shares of common stock outstanding	33,206,114	32,952,543	32,579,813
Income attributable to common stock - assuming dilution	$ 84,219	$ 41,391	$ 91,715
Earnings per share of common stock - assuming dilution	$ 2.26	$ 1.23	$ 2.48
Weighted average shares of common stock outstanding - assuming dilution	37,347,210	33,607,560	37,022,369

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	$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, 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 exercised	-	-	-	-	-	-	-	-	-	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 exercised	-	-	-	-	-	-	-	-	-	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
Comprehensive income:														
Net income, 2003	-	-	-	-	-	-	-	-	-	-	84,219	-	-	84,219
Translation adjustments	-	-	-	-	-	-	-	-	-	-	-	1,237	-	1,237
Reclassification adjustment for settled contracts	-	-	-	-	-	-	-	-	-	-	-	5,272	-	5,272
Changes in fair value of outstanding hedge positions	-	-	-	-	-	-	-	-	-	-	-	127	-	127
Fair value of new hedge positions	-	-	-	-	-	-	-	-	-	-	-	(2,266)	-	(2,266)
Change in accumulated derivative comprehensive income	-	-	-	-	-	-	-	-	-	-	-	3,133	-	3,133
Total comprehensive income, net of tax	-	-	-	-	-	-	-	-	-	-	-	-	-	88,589
Stock options exercised	-	-	207,590	-	-	-	-	24	-	3,570	-	-	-	3,594
Effect of re-priced options	-	-	-	-	-	-	-	-	-	904	-	-	-	904
Officer loans forgiven	-	-	-	-	-	-	-	-	-	-	-	-	295	295
Tax benefit related to stock options exercised	-	-	-	-	-	-	-	-	-	727	-	-	-	727
Dividends declared on common stock	-	-	-	-	-	-	-	-	-	-	(6,684)	-	-	(6,684)
Dividends declared on $2.625 cumulative convertible preferred stock	-	-	-	-	-	-	-	-	-	-	(6,783)	-	-	(6,783)
Conversion of $2.625 cumulative convertible preferred stock	-	(676,344)	850,700	-	-	-	(68)	85	-	(17)	-	-	-	-
Redemption of $2.625 cumulative convertible preferred stock	-	(23,656)	-	-	-	-	(2)	-	-	(1,231)	32	-	-	(1,201)
Balance at December 31, 2003	-	2,060,000	34,135,901	25,016	-	$ -	$ 206	$ 3,438	$ (788)	$385,019	$ 173,076	$ 1,558	$ -	$ 562,509

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

WESTERN GAS RESOURCES, INC.
NOTES TO 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 per share. 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 this 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 November 2003 and in December 2003, the Company issued notices of redemption for approximately 700,000 and 800,000 shares, respectively, of its $2.625 cumulative convertible preferred stock at the liquidation preference plus 0.525% premium. In relation to the notice of redemption issued in November 2003, a total of 850,700 common shares were issued and $1.2 million was paid in cash to complete the redemption. In relation to the notice of redemption issued in December 2003, a total of 989,622 common shares were issued in January 2004, and $672,000 was paid in cash, also in January 2004, to complete the redemption.

In 2002, 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, 2002. 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

Acquisition and Disposition of Gathering Systems. Effective February 1, 2003, the Company acquired several 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. Several of the systems located in the Powder River did not integrate directly into the Company's existing systems, and accordingly these systems were sold. During the year ended December 31, 2003, the income, if any, generated by the assets sold was immaterial for separate presentation as a discontinued operation.

Acquisition of Sand Wash Properties. In August 2003, through the acquisition of the stock of a private corporation for $12.9 million, the Company acquired additional reserves, production and acreage in this area. The assets of this private entity consisted primarily of the remaining interests in various Sand Wash properties operated by the Company.

Toca Processing Facility. In September 2002, the Company sold its Toca processing facility in Louisiana. The sale price was $32.2 million and resulted in a pre-tax loss of approximately $230,000. 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 the Company's Revolving Credit Facility, were used in a February 2003 acquisition of several gathering systems described above.

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, 2003, 2002 and 2001, the Company expended approximately $53.3 million, $71.0 million and $82.1 million, respectively, on this project.

Greater Green River Basin. The Company's assets in southwest Wyoming include 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, Wamsutter gathering and production from the Jonah Field, Pinedale Anticline and Sand Wash areas. During the years ended December 31, 2003, 2002 and 2001, the Company expended approximately $102.5 million, $37.1 million and $28.6 million, respectively, in this area.

Pinnacle Gas Treating, Inc. In December 2000, the Company signed an agreement 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.

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 $67.1 million and $42.1 million of gas and $1.6 million and $1.4 million of NGLs at December 31, 2003 and 2002, 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.

In connection with the adoption of SFAS No. 143 on January 1, 2003, a review was completed of the Company's operating assets. As a result of this review, the operating lives and salvage values of the associated equipment was reevaluated. As a result of this evaluation, the Company extended the useful life of many of its operating assets and adjusted the estimated salvage value of its operating equipment. These adjustments resulted in an approximate $10.7 million, or $0.20 per share of common stock - assuming dilution, decrease in depreciation, depletion and amortization in the year ended December 31, 2003, from the expense calculated using the previous useful lives. The adjustments to the salvage value and depreciable lives of the Company's assets are treated as a revision of an estimate and are accounted for on a prospective basis.

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 developed 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 functional currency of this subsidiary is the Canadian dollar. 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, 2003, 2002 and 2001 were $1.2 million, $283,000 and $(440,000), respectively, net of tax.

Revenue Recognition. In the Gas 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. Gas imbalances on the Company's production are accounted for using the sales method. 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. In June 1998, the Financial Accounting Standards Board, (the "FASB"), issued SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities" effective for fiscal years beginning after June 15, 2000. Under SFAS No. 133, which was subsequently amended by SFAS No. 138 and SFAS No. 149, 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, 2003 total $2.3 million and will be reclassified into earnings during 2004. 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" 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 superceded by SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets". 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 and that assets are to be evaluated at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets. 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.

The Company reviews its assets at the plant facility, the related group of plant facilities or the oil and gas producing field or producing coal seam level. Prior to 2003, the Company completed its impairment analysis on its oil and gas producing properties on an individual well-by-well basis. In the fourth quarter of 2003, the Company conducted a review of its oil and gas producing properties, which included an evaluation of the geologic formations and production history for the Company's producing properties. This review indicated that the cash flows from individual wells in its operating areas were not largely independent of the cash flows of other wells producing in the same field or coal seam. As a result of this review, the Company redefined the asset groupings to a field wide analysis for impairment for the Jonah, Pinedale and Sand Wash Basins and a grouping of all wells drilled into related coal seams for the Powder River Basin. These asset groupings were used to determine if any impairment was necessary for the year ended December 31, 2003 and it was determined that none of the asset groups were impaired. In addition, while the Company did not recognize any impairment of its producing properties in the years ended December 31, 2002 or 2001 under the asset groupings utilized in those years, a reevaluation of those years using our new asset groups also did not result in an impairment of its producing properties.

Cumulative Effect of a Change in Accounting Principle. In June 2001, the FASB issued SFAS No. 143 "Accounting for Asset Retirement Obligations." SFAS No. 143 was 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 adopted SFAS No. 143 on January 1, 2003 and recorded 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 $6.7 million non-cash, after-tax loss from the Cumulative effect of a change in accounting principle.

The following is a reconciliation of the asset retirement obligation for the year ended December 31, 2003 (000's):

Asset retirement obligation as of January 1, 2003	$ 17,801
Liability accrued upon capital expenditures	1,994
Liability settled	(306)
Accretion of discount expense	1,155
Asset retirement obligation as of December 31, 2003	$ 20,644

Exclusive of assets disposed of during 2002, if the Company had adopted SFAS No. 143 as of January 1, 2002, it estimates that the asset retirement obligation at that date would have been $15.7 million, based on the same assumptions used in its calculation of the obligation at January 1, 2003. The estimated 2002 pro forma effect of a hypothetical January 1, 2002 adoption of SFAS No. 143 on net income and earnings per share, for annual and interim periods, is not material.

Earnings Per Share of Common Stock. The Company follows SFAS No. 128, "Earnings per Share", 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 $6.8 million, $8.2 million and $11.2 million for each of the years ended December 31, 2003, 2002 and 2001, respectively. Common stock options and the $2.625 cumulative convertible preferred stock are potential common shares. The following is a reconciliation of the weighted average shares of common stock outstanding to the weighted average common shares outstanding – assuming dilution.

	Year Ended December 31,		
	2003	2002	2001
Weighted average shares of common stock outstanding	33,206,114	32,952,543	32,579,813
Potential common shares from:			
Common stock options	706,677	655,017	970,858
$2.625 Cumulative convertible preferred stock	3,434,419	-	3,471,698
Weighted average shares of common stock outstanding - assuming dilution	37,347,210	33,607,560	37,022,369

The numerators and the denominators for these periods were adjusted to reflect these potential shares, conversion of the $2.625 cumulative convertible preferred stock and any related preferred dividends in calculating fully diluted earnings per share.

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 and 2001, the Company reserved approximately $1.6 million and $2.7 million for doubtful accounts through a charge to Selling and administrative expense. During 2003, the Company did not increase its reserve for doubtful accounts. The Company records a reserve for doubtful accounts on a specific identification basis, and the balance in the reserve for doubtful accounts was $2.3 million and $3.9 million, respectively, at December 31, 2003 and 2002.

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 $28.0 million, $28.1 million, and $30.2 million, respectively, for the years ended December 31, 2003, 2002 and 2001. Capitalized interest associated with construction of new projects was $1.8 million, $1.7 million, and $4.7 million, respectively, for the years ended December 31, 2003, 2002 and 2001. Income taxes paid were $11.1 million, $1.5 million, and $18.7 million, respectively, for the years ended December 31, 2003, 2002 and 2001.

Stock Compensation. As permitted under SFAS No. 123, "Accounting for Stock-Based Compensation", 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.

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 24,719, 59,500, and 118,028 common shares outstanding at December 31, 2003, 2002 and 2001, respectively, which were treated as re-priced options. Based on the Company's stock price at December 31, 2003, 2002 and 2001 of $47.25, $36.85, and $32.32 per share, respectively; expense of $529,000, $224,000 and income of $170,000 was recorded in the years ended December 31, 2003, 2002, and 2001, respectively.

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. Such information was only calculated for the options granted under the 1999 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.

The following is a summary of the options to purchase the Company's common stock granted during the years ended December 31, 2003, 2002 and 2001, respectively.

	Year Ended December 31,		
	2003	2002	2001
1999 Stock Option Plan	-	170,000	413,200
Chief Executive Officer's Plan	-	-	300,000
2002 Stock Option Plan	564,950	187,997	-
2002 Directors' Plan	18,000	18,000	-
Total options granted	582,950	375,997	713,200

The following is a summary of the weighted average fair value per share of the options granted during the years ended December 31, 2003, 2002, and 2001, respectively.

	Year Ended December 31,		
	2003	2002	2001
1999 Stock Option Plan	-	$17.36	$19.26
Chief Executive Officer's Plan	-	-	$21.13
2002 Stock Option Plan	$19.54	$17.44	-
2002 Directors' Plan	$21.39	$22.50	-

These values were estimated using the Black-Scholes option-pricing model with the following assumptions:

	1999 Stock Option Plan		2002 Stock Option Plan		2002 Directors' Plan		Chief Executive Officer's Plan
	2002	2001	2003	2002	2003	2002	2001
Risk-free interest rate	3.40%	5.16%	3.47%	3.41%	2.59%	3.40%	5.16%
Expected life (in years)	7	7	7	7	7	7	7.5
Expected volatility	55%	56%	53%	55%	54%	56%	56%
Expected dividends (quarterly)	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05

Had compensation expense for the Company's 2003, 2002 and 2001 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):

	2003		2002		2001	
	As Reported	Pro forma	As Reported	Pro forma	As Reported	Pro forma
Net income	$ 84,219	$80,779	$50,589	$47,978	$95,637	$93,120
Net income attributable to common stock	77,378	73,938	41,391	38,780	84,470	81,954
Earnings per share of common stock	2.33	2.23	1.26	1.18	2.59	2.52
Earnings per share of common stock - assuming dilution	2.26	2.16	1.23	1.15	2.48	2.41
Stock-based employee compensation cost, net of related tax effects, included in net income	$ 576	N/A	$ 375	N/A	$ (68)	N/A
Stock-based employee compensation cost, net of related tax effects, includable in net income if the fair value based method had been applied	N/A	$4,016	N/A	$2,987	N/A	$2,448

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 the Company's 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, counterparty 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.

SFAS No. 141 and SFAS No. 142. SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Intangible Assets" were issued in June 2001 and became effective for the Company on July 1, 2001 and January 1, 2002, respectively. SFAS No. 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS No. 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS No. 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment. One interpretation being considered relative to these standards is that oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds should be classified separately from oil and gas properties, as intangible assets on the Consolidated Balance Sheet. In addition, the disclosures required by SFAS No. 141 and No. 142 relative to intangibles would be included in the Notes to Consolidated Financial Statements. Historically, the Company has included these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves as part of the Oil and gas properties and equipment, even after SFAS No. 141 and No.142 became effective.

This interpretation of SFAS No. 141 and No. 142 described above would only affect the Consolidated Balance Sheet classification of oil and gas leaseholds. The Company's results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves would continue to be amortized in accordance with accounting rules for oil and gas companies provided in SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies".

At December 31, 2003, the Company had undeveloped leaseholds of $55.9 million that would be classified on the Consolidated Balance Sheet as "intangible undeveloped leaseholds" and developed leaseholds of $31.7 million that would be classified as "intangible developed leaseholds" if the interpretation currently being considered was applied. The Company will continue to classify its oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

FIN 46. In January 2003, the FASB issued Interpretation No. 46, or "FIN 46", "Consolidation of Variable Interest Entities." FIN 46 provides guidance on how to identify a variable interest entity, or 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, as amended, must be adopted at the beginning of the first quarter of 2004. The Company did not create any VIEs after January 31, 2003 and it is continuing to evaluate the impact of FIN 46 on any VIEs created prior to that date and will adopt this pronouncement as required.

Reclassifications. Certain prior years' amounts in the consolidated financial statements and related notes have been reclassified to conform to the presentation used in 2003.

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 1998, the Company joined with other industry participants to form 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, 2003 and 2002, the Company owned an approximate 13% interest in Fort Union and is the construction manager and field operator. The Company accounts for its investment in this entity under the equity method of accounting. Construction and expansions of the gathering header and treating system were project financed by Fort Union. At December 31, 2003, Fort Union had total project financing debt outstanding of $41.7 million. This debt is amortizing on an annual basis and is scheduled to be fully paid in 2009. 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 $5.5 million of the debt of Fort Union. This guarantee is not reflected on the Consolidated Balance Sheet.

The Company has entered into long-term agreements for firm gathering services on 83 MMcf per day of capacity for $0.14 per Mcf on Fort Union. The Company acts as field operator of Fort Union and charges a monthly overhead fee to cover such services. In 2003, 2002 and 2001, the Company received overhead fees from Fort Union totaling $(2,000), $25,000 and $483,000, respectively, and the Company paid to Fort Union a total of $6.4 million, $5.3 million and $3.3 million for gathering services, respectively. At December

31, 2003 and 2002, the Company had a net amount due to Fort Union of $71,000 and $258,000, respectively. At December 31, 2003, the Company's investment in Fort Union totaled $3.3 million and is included in Other assets on the Consolidated Balance Sheet.

Rendezvous. At December 31, 2003 and 2002, the Company owned a 50% interest in Rendezvous Gas Services, L.L.C., ("Rendezvous") 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 2003 and 2002, and at December 31, 2003, the Company had a total of $36.0 million invested in this venture. The investment is included in Other assets on the Consolidated Balance Sheet. The Company accounts for its investment in this entity under the equity method of accounting. The Company charges a monthly overhead fee to act as field operator of Rendezvous and an overhead charge for capital projects it constructs on behalf of the venture. In 2003 and 2002, the Company received overhead fees as field operator from Rendezvous totaling $100,000 in each year and overhead fees on capital projects totaling $825,000 and $352,000, respectively. In 2003 and 2002, the Company paid to Rendezvous a total of $4.7 million and $2.2 million, respectively, for gathering services. At December 31, 2003 and 2002, the Company had a net amount due to Rendezvous of $382,000 and $3.6 million, respectively.

Officer Transactions. In prior years, the Company had 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 were to be forgiven if the employee was continually employed by the Company and upon a resolution of the board of directors. In 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 was forgiven in May 2003. As of December 31, 2003, there were no loans outstanding under these programs and the program is no longer in effect. At December 31, 2002, loans related to 27,500 shares of Common Stock totaling $295,000 were outstanding under these programs. In prior years, the Company had accrued for the forgiveness of these loans.

In October 2001, the Company's former Chief Executive Officer and President retired. The Company had entered into a consulting agreement with this executive 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 also uses financial instruments to reduce 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 a 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 OTC exposures. OTC exposure is marked-to-market daily for the credit review process. The Company's exposure to OTC credit risk is reduced by its ability to require a margin deposit from its counterparties based upon the mark-to-market value of their net exposure. The Company is also subject to margin deposit requirements under these same agreements and under margin deposit requirements for its NYMEX transactions. At December 31, 2003 and 2002, the Company had posted margin deposits totaling $5.7 million and $19.6 million, respectively, with various counterparties.

The use of financial instruments may expose the Company to the risk of financial loss in certain circumstances, including instances when (i) the Company's 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.

All equity hedging 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. Realized gains or losses on these cash flow hedges are recognized in the Consolidated Statement of Operations through Sale of gas or Sale of natural gas liquids when the hedged transactions occur. Realized and unrealized gains or losses represented by the periodic or final cash settlements from economic hedges are included in Price risk management activities on the Consolidated Statement of Operations. Economic hedges are financially settled derivatives that either were not designated or did not qualify as hedges under SFAS No. 133.

To qualify as cash flow hedges, the hedge instruments must be designated as cash flow hedges and changes in their fair value must be highly correlated 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 the price of the commodity, and if applicable, 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 natural gasoline, butane and condensate. The Company's hedges are tested for effectiveness at inception and on a quarterly basis thereafter. Regression analysis based on a five-year period of time is used for this test. Based on the results of the regression analysis, these hedges are expected to continue to be "highly effective" under SFAS No. 133 in the future. Gains or losses from the ineffective portions of changes in the fair value of cash flow hedges are recognized currently in earnings through Price risk management activities. During the year ended December 31, 2003 and 2002, the Company recognized losses of $110,000 and $154,000, respectively, from the ineffective portions of its hedges.

In 2003, in order to properly align the Company's hedged volumes of natural gas to its forecasted equity production, the Company discontinued hedge treatment on financial instruments for 10 MMcf per day of natural gas and 50,000 Barrels per month of ethane. As a result, a pre-tax loss of $2.8 million was reclassified into earnings from Accumulated other comprehensive income. In 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 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 2001.

Account balances related to equity hedging transactions at December 31, 2003 were $1.7 million in Current Assets from price risk management activities, $5.2 million in Current Liabilities from price risk management activities, ($1.3) million in Deferred income taxes payable, net, and a $2.3 million after-tax unrealized loss in Accumulated other comprehensive income, a component of Stockholders' Equity. Based on the commodity prices as of December 31, 2003, the after-tax loss of $2.3 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, 2003, the Company held a notional quantity of approximately 268 Bcf of natural gas futures, swaps and options extending from January 2004 to October 2006 with a weighted average duration of approximately five months. This was comprised of approximately 107 Bcf of long positions and 161 Bcf of short positions in these instruments. 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 87 Bcf of short positions in these instruments.

Crude Oil and NGL Derivative Market Risk. As of December 31, 2003, the Company held a notional quantity of approximately 191,520 MGal of NGL futures, swaps and options extending from January 2004 to December 2004 with a weighted average duration of approximately six months. This was comprised of approximately 120,960 MGal of long positions and 70,560 MGal of short positions in these instruments. 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, 2003, the Company did not hold any NGL futures, swaps or options for settlement beyond 2004. As of December 31, 2003, the estimated fair value of the aforementioned crude oil and NGL options held by the Company was approximately $(4.2) million.

Foreign Currency Derivative Market Risk. As a normal part of its 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, 2003, the net notional value of such contracts was approximately $24.3 million in Canadian dollars, which approximated fair market value. As of December 31, 2002, the net notional value of such contracts was approximately $14.4 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,	
	2003	2002
Master Shelf and Subordinated Notes	$ 245,000	$ 263,333
Variable Rate Revolving Credit Facility	94,000	96,600
Total long-term debt	$ 339,000	$ 359,933

Revolving Credit Facility. The Revolving Credit Facility is with a syndicate of banks and provides for a maximum borrowing commitment of $300 million, which matures on April 24, 2007. At December 31, 2003, $94.0 million was outstanding under this facility. Loans made under this facility are secured by a pledge of the capital stock of the Company's significant subsidiaries. These subsidiaries also guarantee the borrowings under the facility. The Revolving Credit Facility contains a provision that requires the Company to secure loans under the facility with 75% of its oil and gas reserves. This provision would only be triggered in the event of a reduction to a debt rating on the Revolving Credit Facility of Ba3 or lower by Moody's Investors Service, Inc. (or "Moody's") or the reduction to a debt rating on the revolving credit facility of BB- or lower by Standard & Poor's Rating Services, a division of The McGraw-Hill Companies, Inc. (or "S&P"). This facility has been rated Ba1 by Moody's and BB+ by S&P.

The borrowings under the Revolving Credit Facility bear interest at Eurodollar rates or a base rate, as selected by the Company, plus an applicable percentage based on its debt to capitalization ratio. The base rate is the agent's published prime rate. The Company also pays a quarterly facility fee ranging between 0.30% and 0.50%, depending on its debt to capitalization ratio. This fee is paid on the total commitment. At December 31, 2003, the interest rate payable on borrowings under this facility was approximately 2.9%.

Under the Revolving Credit Facility, the Company is subject to a number of covenants, including: maintaining a total debt to capitalization ratio of not more than 55%; maintaining a senior debt to capitalization ratio of not more than 40%; and maintaining a ratio of EBITDA, as defined in the credit facility, to interest and dividends on preferred stock over the last four quarters in excess of 3.25 to 1.0, increasing to 3.75 to 1.0 at March 31, 2004 and to 4.25 to 1.0 at March 31, 2005.

The credit facility ranks equally with borrowings under the Master Shelf Agreement with The Prudential Insurance Company.

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, 2003 are as indicated in the following table (000s):

Issue Date	Amount	Interest Rate	Final Maturity	Principal Payment Schedule
October 27, 1994	$ 25,000	9.24%	October 27, 2004	single payment at maturity
July 28, 1995	40,000	7.61%	July 28, 2007	$10,000 on each of July 28, 2004 through 2007
January 17, 2003	25,000	6.36%	January 17, 2008	single payment at maturity
	$ 90,000			

The Company's borrowings under the Master Shelf Agreement are secured by a pledge of the capital stock of its significant subsidiaries, some of which have also provided a guaranty of payments owed by it under the facility. The Master Shelf Agreement requires the Company to secure loans under the facility with 75% of its oil and gas reserves. This provision would only be triggered in the event of a reduction to the debt rating on the Revolving Credit Facility of Ba3 or lower by Moody's or the reduction to the debt rating on the revolving credit facility of BB- or lower by S&P.

Under the Master Shelf Agreement, the Company is subject to a number of covenants, including: maintaining 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; maintaining a total debt to capitalization ratio of not more than 55% and a senior debt to capitalization ratio of not more than 40%; maintaining a quarterly test of EBITDA, as defined in the Master Shelf Agreement, to interest for the last four quarters in excess of 3.25 to 1.0, increasing to 3.75 to 1.0 at March 31, 2004 and to 4.25 to 1.0 at March 31, 2005; and maintaining a ratio of senior debt to EBITDA of no greater than 4.0 to 1.0.

In the fourth quarter of 2003, the Company utilized funds available under the Revolving Credit Facility to fund $33.3 million in scheduled payments under the Master Shelf Agreement. During 2004, the Company is required to make scheduled payments totaling $35.0 million on this facility. The Company intends to fund these repayments with funds available under the Revolving Credit Facility.

Senior Subordinated Notes. At December 31, 2003, the Company had outstanding $155.0 million of Senior Subordinated Notes due in a single payment in 2009. The Senior Subordinated Notes bear interest at 10% per annum and were priced at 99.225% to yield 10.125%. These notes contain covenants, which include certain limitations on debt incurrence, restricted payments, liens and sales of assets. Under the calculation limiting restricted payments, including common dividends, approximately $76.8 million was available at December 31, 2003. The subordinated notes are unsecured and are guaranteed on a subordinated basis by 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. The senior subordinated notes are callable at the Company's option, in whole or in part, at 105% of par value beginning in June 2004 and are callable at decreasing premiums thereafter.

Covenant Compliance. The Company is in compliance with all covenants in its debt agreements for each of the years ended December 31, 2003, 2002 and 2001.

Approximate future maturities of long-term debt in the year indicated are as follows at December 31, 2003 (000s):

2004	$ 35,000
2005	10,000
2006	10,000
2007	104,000
2008	25,000
Thereafter	155,000
Total	$ 339,000

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, 2003		December 31, 2002	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(000s)		(000s)	
Cash and cash equivalents	$ 26,116	$ 26,116	$ 7,312	$ 7,312
Trade accounts receivable	262,509	262,509	253,587	253,587
Accounts payable	303,186	303,186	242,987	242,987
Long-term debt	339,000	371,553	359,933	365,190
Derivative contracts	$ 6,707	$ 6,707	$ 63	$ 63

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 comprised of fixed and floating rate facilities. The fair market value for the fixed rate debt was estimated using discounted cash flows based upon the Company's current borrowing rates for debt with similar maturities. The floating rate 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, 2003, 2002 and 2001 is comprised of (000s):

	2003	2002	2001
Current:			
Federal	$ 4,002	$ 9,404	$ 14,074
State	265	1,096	(400)
Total Current	4,267	10,500	13,674
Deferred:			
Federal	47,612	18,967	41,225
State	1,714	647	1,590
Total Deferred	49,326	19,614	42,815
Total tax provision (benefit)	$ 53,593	$ 30,114	$ 56,489

Not included above is the tax benefit allocated to the cumulative effect of a change in accounting principle of approximately $4.0 million for the year ended December 31, 2003. There were no such items in 2002 or 2001.

Temporary differences and carry-forwards which give rise to the deferred tax liabilities (assets) at December 31, 2003 and 2002, net of the tax effect of the cumulative change in accounting principle, are as follows (000s):

	2003	2002
Property and equipment	$ 222,884	$ 175,164
Differences between the book and tax basis of acquired assets	11,341	12,101
Hedging derivatives	(1,298)	(3,118)
Total deferred income tax liabilities	232,927	184,147
Alternative Minimum Tax ("AMT") credit carry-forwards	(50,220)	(46,076)
Net Operating Loss ("NOL") carry-forwards	(6,034)	(13,818)
Total deferred income tax assets	(56,254)	(59,894)
Net deferred income taxes payable	$ 176,673	$ 124,253

The change in the net deferred income taxes in 2003 and 2002 includes a $700,000 and $1.2 million tax benefit, respectively, associated with the exercise of incentive stock options.

The differences between the provision for income taxes at the statutory rate and the actual provision for income taxes, before the tax effect of the change in accounting principle, for the years ended December 31, 2003, 2002 and 2001 are summarized as follows (000s):

	2003	%	2002	%	2001	%
Income tax before effect of change in accounting principle at statutory rate	$ 50,588	35.0	$ 28,246	35.0	$ 53,245	35.0
State income taxes, net of federal benefit	2,021	1.4	968	1.2	2,130	1.4
Canada income taxes, effect of disallowed loss on sale of stock and other miscellaneous items	984	0.7	900	1.1	1,114	.7
Total	$ 53,593	37.1	$ 30,114	37.3	$ 56,489	37.1

At December 31, 2003, 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 $16.6 million and $50.2 million, respectively. These carry-forwards expire as follows (000s):

Expiration Dates	NOL	AMT
2018	$ 16,639	$ -
No expiration	-	50,220
Total	$ 16,639	$ 50,220

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. v. Williams Production RMT Company, (Defendant), Civil Action No. CO2-10-394, District Court, County of Sheridan, Wyoming. On October 23, 2002, the Company filed a complaint for declaratory relief and damages related to a dispute arising under a development agreement and other agreements between the parties. On October 24, 2003, the Company reached an agreement with the Defendant to settle these disputes. Under the terms of the settlement agreement, the Defendant and the Company each operate the drilling and production on approximately half of the jointly owned leasehold in the coal-bed methane development of the Powder River Basin of Wyoming. Effective November 1, 2003, the parties have agreed to an expanded area of mutual interest and the Company assumed an expanded area of dedication in its gas gathering operations in the Powder River Basin. The parties have also agreed to modifications to the gas gathering fee schedule. On November 3, 2003, the Company filed, in conjunction with the Defendant, a joint stipulation of voluntary dismissal of this action.

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 filed on June 30, 1997, along with over 300 natural gas companies in 72 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 on the jurisdictional issues is being completed 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 his appeal against this decision was also unsuccessful. The Company believes that Mr. Grynberg's remaining 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 filed on September 23, 1999, 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. The court denied plaintiff's motion for certification as a class and, in the second quarter of 2003, the plaintiff amended and refiled for certification as a class. On May 12, 2003, Mr. Price filed a further claim, *Will Price et al v. Western Gas Resources, Inc. et al., District Court, Stevens County, Kansas, Case No. 03C23*, relating to certain matters previously removed from the foregoing action. The Company believes that Mr. Price's claims are 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.

In the Matter of the Appeal of Lance Oil & Gas Company from a Decision by the Department of Revenue, Docket No. 2003-44, Before the State Board of Equalization for the State of Wyoming. The Wyoming Department of Revenue has conducted an audit of the Company's wholly-owned subsidiary Lance Oil & Gas Company, Inc. for the period from January 1, 1998 through December 31, 1999. On March 24, 2003, the Department of Revenue notified the Company that it had assessed additional severance taxes and increased taxable value for ad valorem tax purposes. The additional severance and ad valorem taxes claimed by the Department of Revenue amount to $196,000 and $351,000, respectively, together with statutory interest. The Company believes that the Wyoming Department of Revenue claims are without merit and intends to vigorously contest their assessments. On April 23, 2003, the Company filed a Notice of Appeal with the Wyoming State Board of Equalization. The hearing has been rescheduled to April 22, 2004. In the event that the Department of Revenue is successful in its argument, the Company's severance and ad valorem taxes will be affected in future years following the 1999 assessment. Although the amounts subject to the audit are immaterial, due to increasing production volumes in subsequent years, any such assessment could be material. At this time, the Company is unable to predict the outcome of this matter.

In the Matter of the Notice of Violation Issued to Mountain Gas Resources, Inc., Department of Environmental Quality, State of Wyoming. The Company's wholly-owned subsidiary received a Notice of Violation issued by the State of Wyoming Department of Environmental Quality for failing to obtain a permit prior to constructing certain dehydration units at facilities in Sublette County, Wyoming. This Notice of Violation was received after the Company self-reported to the Department of Environmental Quality in April 2003 that it had inadvertently failed to submit notices of intent and air permit applications for such dehydration units. The Company settled this matter in the fourth quarter of 2003 for an immaterial amount.

National Pipeline Mapping System. The Company received correspondence from the U.S. Department of Transportation regarding its failure to submit information for incorporation into the National Pipeline Mapping System within nine months of enactment of the Pipeline Safety Improvement Act of 2002. During the fourth quarter of 2003, the Company supplied all required information to the U.S. Department of Transportation Office of Pipeline Safety.

Price Reporting to Gas Trade Publications. In the third quarter of 2003, the Company learned that several employees in its marketing department furnished inaccurate information regarding natural gas transactions to energy publications, which compile and report energy index prices. The Company discovered the inaccuracies during a review of its marketing activities, which is being conducted in response to a subpoena issued by the Commodity Futures Trading Commission (or "CFTC"). These employees have identified inaccuracies associated with reporting of natural gas transactions primarily related to points in Texas. The Company's review of this and other regions is continuing as it responds to the CFTC subpoena. The Company is unable to predict the amount of fines or penalties to be assessed by the CFTC.

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, results of operations or cash flow.

Retirement Plan. The Company provides a Retirement Plan for its present and past employees, or participants. The purpose of the Retirement Plan is to provide a method for the participants to save towards their retirement. Beginning in January 1989, the participants were given the option to invest their contributions in the Western Gas Fund. The Western Gas Fund is comprised of shares of the Company's common stock, purchased in the open market by the trustee, Fidelity Management Trust Company, and short-term investments. A participant's ownership in the Western Gas Fund is measured in Units rather than in shares of common stock. To effectuate participant investment elections and therefore purchases and sales of Units, the trustee purchases and sells the common stock in the open market at market prices.

The Company is required to register the shares of common stock purchased by the trustee of the Retirement Plan under the Securities Act. Although all the purchases by the trustee were made in the open market and in a manner consistent with the Retirement Plan and the investment elections of the participants, the Company has determined that approximately 467,000 shares of its common stock purchased by the trustee beginning August 14, 2001 and ending August 14, 2002 (the "Rescission Period") may not have been properly registered in accordance with the Securities Act. These shares were purchased at an average price of $31.92 per share for total value of $14.9 million. The Company intends to correct this situation by filing a registration statement on Form S-3 with the SEC providing for a rescission offer to certain of the plan participants as described below. This registration statement is expected to be filed during the first quarter of 2004.

Any participant who elected to allocate a percentage of such participant's funds in the Retirement Plan to the purchase of Units in the Western Gas Fund at any time during the Rescission Period, and who still holds those Units during the period of the rescission offer, may direct a sale of those Units to the Company at the price the participant paid for the Units, plus interest. This election would be beneficial to any participant who purchased Units at a price higher than the Company's stock price during the period of the rescission offer. At December 31, 2003, the Company's common stock price was $47.25 per share. At December 31, 2003, approximately 144,000 shares of its common stock were held by the Western Gas Fund. The trustee of the Western Gas Fund sold the remaining 326,000 shares of the Company's common stock acquired during the Rescission Period. If a participant has already directed and caused the sale of those Units purchased during the Rescission Period at a loss, then the trustee or the participant may receive from the Company, the price paid for those Units, plus interest, less the sale proceeds. This election would be beneficial to any participant who sold Units at a loss.

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, results of operations or cashflows. The Company also believes that the amounts subject to the rescission offer are immaterial for separate classification on the Consolidated Balance Sheet at December 31, 2003 and 2002.

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 one month to ten years. The majority of the leases for compression have purchase options at various times throughout the primary terms of the agreements and have renewal provisions. Rental payments under operating leases have totaled $13.8 million, $10.8 million and $3.1 million in 2003, 2002 and 2001, respectively. Future operating lease payments by year under these leases are as follows (000s):

2004	$ 12,662
2005	13,036
2006	12,779
2007	11,900
2008	10,885
Thereafter	15,011
Total	$ 76,273

Firm Transportation Capacity. The Company enters into firm transportation agreements with interstate pipeline companies as a part of its marketing operations and to ensure that its equity production has access to downstream markets. At December 31, 2003, these agreements have terms ranging from one month to fourteen years. Payments under these agreements have totaled $26.4 million, $29.2 million and $8.8 million in 2003, 2002 and 2001, respectively. Future payments by year under these agreements are as follows (000s):

2004	$ 29,262
2005	28,314
2006	28,123
2007	27,890
2008	24,482
Thereafter	77,453
Total	$ 215,524

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 totaled $5.2 million, $5.1 million and $3.9 million in 2003, 2002 and 2001, respectively. As of December 31, 2003, the Company had contracts in place for approximately 16.3 Bcf of storage capacity at various third-party facilities. The associated contract periods have an average term of twenty-nine months. Future payments by year under these agreements are as follows (000s):

2004	$ 6,198
2005	5,016
2006	4,434
2007	1,907
2008	1,136
Thereafter	1,761
Total	$ 20,452

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; Transportation; and Marketing. 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.

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.

Gas Gathering, Processing and Treating. In this segment, the Company connects producers' wells (including those of its Exploration and Production segment) to its gathering systems for delivery to its processing or treating plants, processes the natural gas to extract NGLs and treats the natural gas in order to meet pipeline specifications. In some areas, where no processing is required, the Company gathers and compresses producers' gas and delivers it to pipelines for further delivery to market. Except for volumes taken in kind by the Company's producers, the Marketing segment sells the residue gas and NGLs extracted at most of its facilities. In this segment, the Company recognizes revenues 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 79% of the Company's plant facilities' gross margins, or revenues at the plants less product purchases, for the month of December 2003 were under 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 NGLs.

Approximately 14% of the Company's plant facilities' gross margins for the month of December 2003 were under 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 7% of the Company's plant facilities' gross margin for the month of December 2003 was under contracts with "keepwhole" arrangements or wellhead purchase contracts. 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.

Transportation. The Transportation segment reflects the operations of the Company's MIGC, Inc. and MGTC, Inc. 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 segment's firm capacity contracts at December 31, 2003 range in duration from one month to five years.

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. 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 marketing of products purchased from third parties typically results in low operating margins relative to the sales price. The Company sells its products under agreements with varying terms and conditions in order to match seasonal and other changes in demand. This segment also markets gas and NGLs produced by its gathering, processing, treating and production assets. Also included in this segment are its Canadian marketing operations, which are conducted through its wholly-owned subsidiary WGR Canada, Inc. and are immaterial for separate presentation.

During the years ended December 31, 2003, 2002 and 2001, the Company sold gas to a variety of customers including end-users, pipelines, energy merchants, local distribution companies and others. In 2003, no single customer accounted for more than approximately 6% of the Company's consolidated revenues from the sale of gas, or 5% of total consolidated revenue. In 2002, two customers accounted for approximately 10% of the Company's consolidated revenues from the sale of gas, or 9% of total consolidated revenue. One of these customers is an energy merchant and the other customer is an electric utility. In 2001, one customer accounted for approximately 5% of the Company's consolidated revenues from the sale of gas, or 4% of total consolidated revenue. This customer is a wholly owned subsidiary of a major integrated oil company.

During the years ended December 31, 2003, 2002 and 2001, the Company sold NGLs to a variety of customers including end-users, fractionators, chemical companies, energy merchants and other customers. In 2003, two customers accounted for approximately 49% of the Company's consolidated revenues from the sale of NGLs, or 6% of total consolidated revenue. One of these customers is a large integrated energy company and the other is a large petrochemical company. 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.

The following table sets forth the Company's segment information as of and for the three years ended December 31, 2003, 2002 and 2001 (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. Prior period amounts in the segment information have been reclassified to conform to the presentation used in 2003.

	Gas Gathering, Processing and Treating	Exploration and Production	Marketing	Trans-portation	Corporate	Elim-inating Entries	Total
Year Ended December 31, 2003							
Revenues from unaffiliated customers							
Sale of gas	$ 5,041	$ 4,038	$ 2,476,702	$ 1,098	$ -	$ -	$ 2,486,879
Sale of natural gas liquids	11	-	357,504	-			357,515
Equity hedges:							
Residue	(2,358)	(21,505)	-	-	-	-	(23,863)
Liquids	(11,407)	-	-	-	-	-	(11,407)
Gathering, processing and transportation revenue	76,628	-	-	7,051	(7)	-	83,672
Total revenues from unaffiliated customers	67,915	(17,467)	2,834,206	8,149	(7)	-	2,892,796
Inter-segment revenues	1,081,300	221,266	38,510	14,093	58	(1,355,227)	-
Price risk management activities	(11)	(866)	(20,508)	-	-	-	(21,385)
Interest income	5	42	-	3	12,485	(12,535)	-
Other, net	1,967	21	4	42	565	-	2,599
Total revenues	1,151,176	202,996	2,852,212	22,287	13,101	(1,367,762)	2,874,010
Product purchases	948,518	2,289	2,820,495	2,982	-	(1,317,843)	2,456,441
Plant operating and transportation expense	83,368	329	318	7,680	(721)	(2,630)	88,344
Oil and gas exploration and production expense	-	86,855	-	-	-	(34,610)	52,245
Earnings from equity investments	(7,356)	-	-	-	-	-	(7,356)
Operating profit	126,646	113,523	31,399	11,625	13,822	(12,679)	284,336

Depreciation, depletion and amortization	30,676	33,322	141	1,689	8,078	-	73,906
Selling and administrative expense	-	-	-	-	40,481	(58)	40,423
(Gain) loss from sale of assets	123	(194)	-	586	53	(724)	(156)
Interest expense	-	24	262	(154)	38,030	(12,535)	25,627
Segment profit	$ 95,847	$ 80,371	$ 30,996	$ 9,504	$(72,820)	$ 638	$ 144,536
Identifiable assets							
Other allocated assets	$ 4,067	$ 7,001	$ 113,895	$ 40,628	$ 325,591	$ (66,708)	$ 424,474
Investment in others	-	-	-	-	632,622	(593,333)	39,289
Capital assets	608,623	288,954	1,531	39,010	57,912	731	996,761
Total identifiable assets	$ 612,690	$ 295,955	$ 115,426	$ 79,638	$1,016,125	$ (659,310)	$ 1,460,524

	Gas Gathering, Processing and Treating	Exploration and Production	Marketing	Transportation	Corporate	Eliminating Entries	Total
Year Ended December 31, 2002							
Revenues from unaffiliated customers							
Sale of gas	$ 2,156	$ 1,497	$ 2,085,760	$ 1,252	$ -	$ -	$ 2,090,665
Sale of natural gas liquids	17	-	317,743	-			317,760
Equity hedges:							
Residue	3,238	24,846	-	-	-	-	28,084
Liquids	(8,247)	-	-	-	-	-	(8,247)
Gathering, processing and transportation revenue	56,806	281	-	8,345	169	-	65,601
Total revenues from unaffiliated customers	53,970	26,624	2,403,503	9,597	169	-	2,493,863
Inter-segment revenues	638,807	112,868	22,868	15,794	87	(790,424)	-
Price risk management activities	(233)	589	(9,241)	-	-	-	(8,885)
Interest income	44	43	10	1	8,514	(8,612)	-
Other, net	3,595	19	6	2	(660)	1,758	4,720
Total revenues	696,183	140,143	2,417,146	25,394	8,110	(797,278)	2,489,698
Product purchases	532,963	2,698	2,380,446	935	-	(759,863)	2,157,179
Plant operating and transportation expense	74,119	170	290	8,133	234	(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	93,554	74,126	36,410	16,326	7,876	(6,857)	221,435
Depreciation, depletion and amortization	41,959	26,770	158	1,675	6,443	-	77,005
Selling and administrative expense	-	-	-	-	35,882	(54)	35,828
(Gain) loss from sale of assets	877	(323)	-	476	494	(576)	948
Interest expense	-	66	132	(26)	35,391	(8,612)	26,951
Segment profit	$ 50,718	$ 47,613	$ 36,120	$ 14,201	$(70,334)	$ 2,385	$ 80,703
Identifiable assets							
Other allocated assets	$ 34,021	$ 911	$ 118,854	$ 24,534	$ 285,469	$ (53,907)	$ 409,882
Investment in others	2,839	-	-	-	467,600	(444,823)	25,616
Capital assets	551,094	225,943	7	42,072	47,523	7	866,646
Total identifiable assets	$ 587,954	$ 226,854	$ 118,861	$ 66,606	$ 800,592	$ (498,723)	$ 1,302,144

	Gas Gathering, Processing and Treating	Exploration and Production	Marketing	Trans-portation	Corporate	Elim-inating Entries	Total
Year ended December 31, 2001							
Revenues from unaffiliated customers							
Sale of gas	$ 3,096	$ 2,112	$ 2,850,506	$ 1,390	$ -	$ -	$ 2,857,104
Sale of natural gas liquids	(156)	-	421,958	-	-	-	421,802
Equity hedges:							
Residue	7,833	1,486	-	-	-	-	9,319
Liquids	2,313	-	-	-	-	-	2,313
Gathering, processing and transportation revenue	48,189	(14)	-	7,187	36	-	55,398
Total revenues from unaffiliated customers	61,275	3,584	3,272,464	8,577	36	-	3,345,936
Inter-segment revenues	815,484	112,951	27,483	17,103	176	(973,197)	-
Price risk management activities	208	(188)	2,527	-	-	-	2,547
Interest income	23	12	-	1	12,824	(12,860)	-
Other, net	3,706	10	17	-	946	-	4,679
Total revenues	880,696	116,369	3,302,491	25,681	13,982	(986,057)	3,353,162
Product purchases	678,915	2,789	3,254,654	514	-	(949,922)	2,986,950
Plant operating and transportation expense	69,223	116	425	8,865	(1,030)	(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	134,348	64,187	47,412	16,302	15,012	(12,319)	264,942
Depreciation, depletion and amortization	39,060	17,716	161	1,646	5,579	-	64,162
Selling and administrative expense	-	-	-	-	34,326	(54)	34,272
Gain from sale of assets	(11,118)	(394)	-	511	253	-	(10,748)
Interest expense	-	-	-	-	36,292	(11,162)	25,130
Segment profit	$ 106,406	$ 46,865	$ 47,251	$ 14,145	$(61,438)	$ (1,103)	$ 152,126
Identifiable assets							
Other allocated assets	$ 40,050	$ 3,856	$ 133,527	$ 9,351	$ 288,850	$ (63,115)	$ 412,519
Investment in others	1,806	-	-	-	409,525	(404,215)	7,116
Capital assets	573,362	182,414	29	46,010	46,492	-	848,307
Total identifiable assets	$ 615,218	$ 186,270	$ 133,556	$ 55,361	$ 744,867	$ (467,330)	$ 1,267,942

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 the three years ended December 31, 2003, the match of employee contributions was a sliding scale of 60% to 100% of the first 5% of employee compensation based upon years of service. Contributions are made to Fidelity Management Trust Company, as trustee. The trustee invests the funds in accordance with the participants' investment elections into mutual funds and a fund to purchase Company stock. The discretionary contributions made by the Company were $2.2 million, $1.9 million and $2.3 million, for the years ended December 31, 2003, 2002 and 2001, respectively. The matching contributions were approximately $1.4 million, $1.3 million and $1.3 million for the years ended December 31, 2003, 2002 and 2001, 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 Directors 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 were forgiven as the employee was continually employed by the Company and as resolved by the board of directors. As of December 31, 2002, loans related to 27,500 shares of common stock totaling $295,000 were outstanding under these terms. There were no loans outstanding as of December 31, 2003.

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 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 terminated on March 29, 2003. The 1997 Plan and the 1999 Plan will terminate on the earlier of May 21, 2007 and May 21, 2009, respectively, or the date on which all the respective options granted under each of the plans have been exercised in full. Although options covering 372,602 shares are available to be granted under the 1997 Plan, no further options will be granted under this 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 Chief Executive Officer 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. This option plan will terminate on the earlier of October 15, 2010 or the date on which all options granted under the plan have been exercised in full.

2002 Non-Employee Directors Stock Option Plan. Effective May 2002, the stockholders 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 the Company's 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 the Company's 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. The 2002 Directors 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 2003 and 2002, a total of 16,000 and 18,000 options, respectively, were granted under this plan.

2002 Stock Option Plan. Effective May 2002, the stockholders 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 2003 and 2002, a total of 564,950 and 187,997 options, respectively, were granted under this plan.

Under each of the 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 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 vested 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, 2003...	$ 0.01– 5.00	-	-	13,770	-	-	-	-
	$ 5.01–10.00	8,350	-	40,863	-	-	-	-
	$10.01-15.00	-	-	17,750	-	-	-	-
	$15.01-20.00	-	-	14,910	400	-	-	-
	$20.01-25.00	-	-	-	30,881	-	-	-
	$25.01-30.00	-	-	-	5,000	150,000	-	-
	$30.01-35.00	-	-	-	101,552	-	42,441	-
	$35.01-40.00	-	-	-	186,200	-	-	5,333
	TOTAL	8,350	-	87,293	324,003	150,000	42,441	5,333
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	-	-	-
Available for Grant:								
December 31, 2003...	-	-	-	-	60,438	-	503,486	78,000
December 31, 2002...	-	-	-	-	-	-	1,062,003	92,000
December 31, 2001...	-	-	-	-	287,634	-	-	-

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 12/31/00		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 expired...	$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 expired...	$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
Granted................	$32.95-33.45	-	-	-	-	-	564,950	16,000
Exercised..............	$4.59-35.00	-	(8,014)	(72,112)	(65,201)	-	(18,080)	-
Forfeited or expired...	$4.59-36.34	-	(47,013)	-	(334)	-	(6,433)	(2,000)
Balance 12/31/03		8,350	-	87,293	565,848	300,000	728,434	32,000
Weighted-average remaining contractual life (years)		2.9	-	2.9	4.5	5.3	6.5	5.9

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 12/31/00	$ 5.51	19.35	7.81	20.79	-	-	-
Granted............................	-	-	-	34.72	$ 25.01	-	-
Exercised..........................	-	(19.55)	(7.22)	(18.30)	-	-	-
Forfeited or expired..........	-	(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 expired..........	-	(35.00)	(5.92)	(26.46)	-	-	-
Balance 12/31/02	$ 5.51	$ 19.73	$ 9.73	$ 32.68	$ 25.01	$ 32.98	$ 37.82
Granted............................	-	-	-	-	-	37.81	38.76
Exercised..........................	-	(18.41)	(10.59)	(23.57)	-	(33.04)	-
Forfeited or expired..........	-	(29.01)	-	(23.45)	-	(32.95)	(37.82)
Balance 12/31/03	$ 5.51	$ -	$ 9.03	$ 33.73	$ 25.01	$ 36.73	$ 38.29

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

Costs. The following tables set forth capitalized costs at December 31, 2003, 2002 and 2001 and costs incurred for oil and gas producing activities for the years ended December 31, 2003, 2002 and 2001 (000s):

	2003	2002	2001
Capitalized costs:			
Proved properties	$ 315,635	$ 239,579	$ 194,596
Unproved properties	83,384	64,451	40,137
Total	399,019	304,030	234,733
Less accumulated depreciation and depletion	(111,658)	(79,050)	(53,359)
Net capitalized costs	$ 287,361	$ 224,980	$ 181,374
Costs incurred:			
Acquisition of properties			
Proved	$ 14,202	$ 426	$ 1,624
Unproved	10,279	2,770	5,332
Development costs	60,479	48,648	63,263
Exploration costs	18,089	22,547	2,141
Total costs incurred	$ 103,049	$ 74,391	$ 72,360

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, 2003, 2002 and 2001 are as follows (000s):

	2003	2002	2001
Revenues from sale of oil and gas:			
Sales	$ 5,905	$ 2,227	$ 4,517
Transfers	220,107	112,137	110,532
Total	226,012	114,364	115,049
Production costs	(86,800)	(65,536)	(49,421)
Exploration costs	(6,764)	(3,543)	(3,234)
Depreciation, depletion and amortization	(31,385)	(25,691)	(17,175)
Income tax expense	(57,342)	(7,558)	(15,827)
Results of operations	$ 43,721	$ 12,036	$ 29,392

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 there from 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, 2003, 2002 and 2001 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, 2000	408,494	439
Revisions of previous estimates	(18,415)	(110)
Extensions and discoveries	115,672	377
Production	(35,514)	(45)
December 31, 2001	470,237	661
Revisions of previous estimates	(88,344)	51
Extensions and discoveries	246,704	554
Sales of reserves in place	(532)	-
Production	(47,401)	(53)
December 31, 2002	580,664	1,213
Revisions of previous estimates	(65,474)	571
Extensions and discoveries	191,751	887
Purchases of reserves in place	14,005	57
Production	(52,222)	(75)
December 31, 2003	668,724	2,653
Proved developed reserves, included above:		
December 31, 2000	208,218	147
December 31, 2001	252,266	262
December 31, 2002	265,300	400
December 31, 2003	282,374	823

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. Also included in this caption are asset retirement obligations.

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, 2003, 2002 and 2001 is as follows (000s):

	2003	2002	2001
Future cash inflows	$ 3,152,573	$ 1,587,891	$ 691,188
Future production costs	(710,999)	(463,471)	(210,242)
Future development costs	(275,302)	(193,255)	(110,365)
Future income tax expense	(740,314)	(305,263)	(108,270)
Future net cash flows	1,425,958	625,902	262,311
10% annual discount for estimated timing of cash flows	(740,598)	(265,250)	(90,941)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 685,360	$ 360,652	$ 171,370

Principal changes in the Company's estimated discounted future net cash flows for the years ended December 31, 2003, 2002 and 2001 are as follows (000s):

	2003	2002	2001
January 1	$ 360,652	$ 171,370	$ 967,911
Sales and transfers of oil and gas produced, net of production costs	(139,211)	(50,828)	(65,628)
Net changes in prices and production costs related to future production	578,659	263,448	(1,349,674)
Development costs incurred during the period	60,479	40,753	50,494
Changes in estimated future development costs	(22,565)	(42,869)	(37,115)
Changes in extensions and discoveries	272,110	148,114	57,300
Revisions of previous quantity estimates	(321,395)	(87,705)	(34,596)
Purchases (sales) of reserves in place	22,898	(586)	-
Accretion of discount	53,655	24,118	147,393
Net change in income taxes	(179,922)	(105,163)	435,285
December 31	$ 685,360	$ 360,652	$ 171,370

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 Before Cumulative Effect of Change in Accounting Principle	Earnings Per Share of Common Stock Before Cumulative Effect of Change in Accounting Principle	Net Income	Earnings Per Share of Common Stock	Earnings Per Share of Common Stock – Assuming Dilution
2003 quarter ended:							
March 31	$ 888,106	$ 65,490	$ 30,099	$ .85	$ 23,375	$ .65	$ .63
June 30	660,491	48,935	20,900	.58	20,900	.58	.56
September 30	666,800	49,193	20,889	.57	20,889	.57	.56
December 31	658,613	46,812	19,055	.53	19,055	.53	.51
	$ 2,874,010	$ 210,430	$ 90,943	$ 2.53	$ 84,219	$ 2.33	$ 2.26
2002 quarter ended:							
March 31	$ 615,915	$ 27,954	$ 8,000	$ .18	$ 8,000	$ .18	$ .18
June 30	614,128	40,393	13,766	.35	13,766	.35	.34
September 30	614,082	37,560	13,387	.34	13,387	.34	.34
December 31	645,572	37,888	15,436	.39	15,436	.39	.37
	$ 2,489,698	$ 144,430	$ 50,589	$ 1.26	$ 50,589	$ 1.26	$ 1.23

(a) Excludes selling and administrative, interest and income tax expenses, (gains) or losses on sale of assets and the cumulative effect of the change in accounting principle.

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, 2003, 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").

The Company's subsidiaries that did not guarantee the Company's payment obligations under its financing facilities during the years ended December 31, 2003, 2002 and 2001 included Western Power Services, Inc., Western Gas Resources-Westana, Inc. and WGR Canada, Inc., and Western Gas Resources – Sand Wash, 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, 2003 and 2002. The Statement of Operations and Statement of Cash Flows data are presented for the years ended December 31, 2003, 2002 and 2001.

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, 2003
(000s)

	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Entries	Total
ASSETS					
Current assets:					
Cash and cash equivalents	$ 24,371	$ 122	$ 1,623	$ -	$ 26,116
Trade accounts receivable, net	149,889	99,485	14,786	(1,651)	262,509
Inventory	46,670	1,686	21,948	-	70,304
Assets held for sale	-	-	-	-	-
Assets from price risk management activities	17,149	-	-	-	17,149
Other	9,782	(149)	1,592	-	11,225
Total current assets	247,861	101,144	39,949	(1,651)	387,303
Total property and equipment, net	410,456	504,824	80,858	623	996,761
Other assets:					
Gas purchase contracts, net	7,386	21,833	-	-	29,219
Assets from price risk management activities	1,466	-	-	-	1,466
Other assets	78,123	(15)	8	(71,630)	6,486
Investments in subsidiaries	578,640	36,013	3,276	(578,640)	39,289
Total other assets	665,615	57,831	3,284	(650,270)	76,460
Total assets	$ 1,323,932	$ 663,799	$ 124,091	$ (651,298)	$ 1,460,524
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities:					
Accounts payable	$ 233,708	$ 43,447	$ 28,597	$ (2,566)	$ 303,186
Accrued expenses	16,145	23,544	2,447	-	42,136
Liabilities from price risk management activities	10,603	-	-	-	10,603
Dividends payable	3,056	-	-	-	3,056
Total current liabilities	263,512	66,991	31,044	(2,566)	358,981
Long-term debt	339,000	44,967	19,931	(64,898)	339,000
Other long-term liabilities	11,534	9,698	825	-	22,057
Liabilities from price risk management activities	1,304	-	-	-	1,304
Deferred income taxes payable	146,073	29,805	5,989	(5,194)	176,673
Total liabilities	761,423	151,461	57,789	(72,658)	898,015
Total stockholders' equity	562,509	512,338	66,302	(578,640)	562,509
Total liabilities and stockholders' equity	$ 1,323,932	$ 663,799	$ 124,091	$ (651,298)	$ 1,460,524

Supplemental Condensed Consolidating Statement of Operations
For the year ended December 31, 2003
(000s)

	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Entries	Total
Total revenues	$ 3,685,973	$ 367,656	$ 188,143	$ (1,367,762)	$ 2,874,010
Costs and expenses:					
Product purchases	3,514,374	80,097	178,347	(1,316,377)	2,456,441
Plant operating expense	61,402	28,318	2,883	(4,259)	88,344
Oil and gas exploration and production costs	2,816	83,721	156	(34,448)	52,245
Depreciation, depletion and amortization	27,015	44,035	2,856	-	73,906
Selling and administrative expense	38,805	1,443	233	(58)	40,423
(Gain) loss on sale of assets	(66)	634	-	(724)	(156)
Earnings from equity investments	(127,867)	(4,986)	(2,370)	127,867	(7,356)
Interest expense	24,958	12,307	258	(11,896)	25,627
Total costs and expenses	3,541,437	245,569	182,363	(1,239,895)	2,729,474
Income before income taxes	144,536	122,087	5,780	(127,867)	144,536
Total provision for income taxes	53,593	-	-	-	53,593
Income before cumulative change in accounting principle	90,943	122,087	5,780	(127,867)	90,943
Cumulative effect of change in accounting principle	6,724	4,969	253	(5,222)	6,724
Net income	$ 84,219	$ 117,118	$ 5,527	$ (122,645)	$ 84,219

Supplemental Condensed Consolidating Statement of Cash Flows
For the year ended December 31, 2003
(000s)

	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Entries	Total
Net cash provided by operating activities	$ 154,210	$ 93,299	$ 14,174	$ (12,951)	$ 248,732
Cash flows from investing activities:					
Purchases of property and equipment, including acquisitions	(84,097)	(80,448)	(25,267)	1,494	(188,318)
Proceeds from the disposition of property and equipment	5,579	1,893	4	(1,494)	5,982
Other net cash used in investing activities	(25,616)	(14,750)	12,666	12,951	(14,749)
Net cash used in investing activities	(104,134)	(93,305)	(12,597)	12,951	(197,085)
Cash flows from financing activities:					
Payments on revolving credit facility	(1,024,900)	-	-	-	(1,024,900)
Borrowings under revolving credit facility	1,022,300	-	-	-	1,022,300
Dividends paid	(13,875)	-	-	-	(13,875)
Other net cash used in financing activities	(16,368)	-	-	-	(16,368)
Net cash used in financing activities	(32,843)	-	-	-	(32,843)
Net decrease in cash and cash equivalents	17,233	(6)	1,577	-	18,804
Cash and cash equivalents at beginning of year	7,138	128	46	-	7,312
Cash and cash equivalents at end of year	$ 24,371	$ 122	$ 1,623	$ -	$ 26,116

Supplemental Condensed Consolidating Balance Sheet
As of December 31, 2002
(000s)

	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	737	7,076	-	44,219
Assets held for sale	3,250	-	-	-	3,250
Assets from price risk management activities	34,873	-	-	-	34,873
Other	29,847	(2,718)	572	-	27,701
Total current assets	368,022	12,160	18,076	(27,316)	370,942
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	64,438	(208)	5	(56,625)	7,610
Investments in subsidiaries	444,823	22,777	2,839	(444,823)	25,616
Total other assets	517,389	45,771	2,844	(501,448)	64,556
Total assets	$ 1,234,348	$ 524,469	$ 72,191	$ (528,864)	$ 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	483,068	395,740	49,083	(444,823)	483,068
Total liabilities and stockholders' equity	$ 1,234,348	$ 524,469	$ 72,191	$ (528,864)	$ 1,302,144

Supplemental Condensed Consolidating Statement of Operations
For the year ended December 31, 2002
(000s)

	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	-	77,005
Selling and administrative expense	33,066	2,562	254	(54)	35,828
(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	24,498	8,548	132	(6,227)	26,951
Total costs and expenses	2,863,315	179,347	122,405	(756,072)	2,408,995
Income before income taxes	79,720	34,137	8,052	(41,206)	80,703
Total provision for income taxes	29,131	-	983	-	30,114
Net income	$ 50,589	$ 34,137	$ 7,069	$ (41,206)	$ 50,589

Supplemental Condensed Consolidating Statement of Cash Flows
For the year ended December 31, 2002
(000s)

	Parent Company	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Entries	Total
Net cash provided by operating activities	$ 24,124	$ 96,812	$ 10,200	$ -	$ 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)	(5,210)	-	(15,037)
Net cash used in investing activities	1,739	(94,851)	(12,659)	-	(105,772)
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 Statement of Operations
For the year ended December 31, 2001
(000s)

	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	21,019	14,054	488	(10,431)	25,130
Total costs and expenses	3,757,160	174,918	190,401	(921,443)	3,201,036
Income before income taxes	152,126	63,145	2,062	(65,207)	152,126
Total provision for income taxes	56,489	2,460	-	(2,460)	56,489
Net income	$ 95,637	$ 60,685	$ 2,062	$ (62,747)	$ 95,637

Supplemental Condensed Consolidating Statement of Cash Flows
For the year ended December 31, 2001
(000s)

	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

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

None.

ITEM 9A. 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 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.

Based on their evaluation of the Company's disclosure controls and procedures as of the end of the period covered by this report, the Company's Chief Executive Officer and President and the Executive Vice-President – Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective in ensuring that the information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms.

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, 13 and 14 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 7, 2004 and is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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 40 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. (previously filed as Exhibit 3.1 to our 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. (previously filed as Exhibit 3.2 to our Registration Statement on Form S-1, Registration No. 33-31604 and incorporated herein by reference).

3.3 Certificate of Designation, Preferences and Rights of Series A Junior Participating Preferred Stock (previously filed as part of Exhibit 1 to our Form 8-A filed on March 30, 2001 and incorporated herein by reference).

3.4 Certificate of Designation of the $2.625 Cumulative Convertible Preferred Stock of Western Gas Resources, Inc. (previously filed in our Current Report on Form 8-K filed on February 25, 1994 and incorporated herein by reference).

3.5 Amended and Restated Bylaws of Western Gas Resources, Inc., adopted by the Board of Directors on April 7, 2003 (previously filed as Exhibit 3.5 to our Quarterly Report on Form 10-Q filed on May 14, 2003 and incorporated herein by reference).

4.1 Rights Agreement, dated as of March 22, 2001 between Western Gas Resources, Inc., and Fleet National Bank as Rights Agent, including exhibits thereto (previously filed as Exhibit 1 to our Form 8-A filed on March 30, 2001 and incorporated herein by reference).

4.2 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 (previously filed as Exhibit 28 to our Quarterly Report on Form 10-Q filed on August 13, 1999 and incorporated herein by reference).

4.3 Western Gas Resources, Inc. First Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated October 19, 1999 (previously filed as Exhibit 4.10 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference).

4.4 Western Gas Resources, Inc. Second Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated September 29, 2000 (previously filed as Exhibit 4.11 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference).

4.5 Western Gas Resources, Inc. Third Supplemental Indenture to 10% Senior Subordinated Notes due 2009 dated January 3, 2001 (previously filed as Exhibit 4.12 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference).

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

10.2 Amendment No. 1 to Registration Rights Agreement, dated 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. (previously filed as Exhibit 4.2 to our Quarterly Report on Form 10-Q filed for the quarter ended June 30, 1991 and incorporated herein by reference).

10.3 Agreement to provide loans to exercise key employees' common stock options (previously filed as Exhibit 10.26 to our Annual Report on Form 10-K filed for the fiscal year ended December 31, 1991 and incorporated herein by reference).*

10.4 Second Amended and Restated Master Shelf Agreement, effective January 31, 1996, by and between Western Gas Resources, Inc. and Prudential Company of America (previously filed as Exhibit 10.49 to our Annual Report on Form 10-K filed on March 22, 1996 and incorporated herein by reference).

10.5 Letter Amendment No. 1, dated November 21, 1997, 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. †

10.6 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 (previously filed as Exhibit 10.22 to our Quarterly Report on Form 10-Q filed on May 13, 1999 and incorporated herein by reference).

10.7 Limited Waiver, Consent, Release and Amendment No. 3 to the Second Amended and Restated Master Shelf Agreement, entered into as of June 1, 1999, by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America and Pruco Life Insurance Company (previously filed as Exhibit 10.14 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference.)

10.8 Limited Waiver, Consent, Release and Amendment No. 4 to the Second Amended and Restated Master Shelf Agreement, dated August 25, 2000, by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America and Pruco Life Insurance Company (previously filed as Exhibit 10.24 to our Quarterly Report on Form 10-Q filed on November 13, 2000 and incorporated herein by reference).

10.9 Waiver and Consent to the Second Amended and Restated Master Shelf Agreement, dated November 22, 2000, by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America and Pruco Life Insurance Company (previously filed as Exhibit 10.20 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference).

10.10 Letter Amendment No. 5, dated March 30, 2001, to the Second Amended and Restated Master Shelf Agreement, by and between Western Gas Resources, Inc., and The Prudential Insurance Company of America (previously filed as Exhibit 10.25 to our Quarterly Report on Form 10-Q filed on May 14, 2001 and incorporated herein by reference).

10.11 Letter Amendment No. 6, dated March 1, 2002, 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 (previously filed as Exhibit 10.27 to our Quarterly Report on Form 10Q filed on May 14, 2002 and incorporated herein by reference).

10.12 Third Amended and Restated Master Shelf Agreement, dated as of December 19, 1991 (effective as of January 13, 2003), by and among Western Gas Resources, Inc. and The Prudential Insurance Company of America, Pruco Life Insurance Company, Prudential Investment Management Company, Inc. and ING Life Insurance & Annuity Company (previously filed as Exhibit 10.29 to our Annual Report on Form 10-K filed on March 24, 2003 and incorporated herein by reference).

10.13 Letter Amendment No. 1 to Third Amended and Restated Master Shelf Agreement, dated as of April 24, 2003, by and among Western Gas Resources, Inc., The Prudential Insurance Company of America, Pruco Life Insurance Company, Prudential Investment Management, Inc. and ING Life Insurance & Annuity Company (previously filed as Exhibit 10.5 to our Quarterly Report on Form 10Q filed on May 13, 2003 and incorporated herein by reference).

10.14 Loan Agreement, dated April 29, 1999, by and among Western Gas Resources, Inc. and NationsBank, as agent, and the Lenders (previously filed as Exhibit 10.20 to our Quarterly Report on Form 10-Q filed on May 13, 1999 and incorporated herein by reference).

10.15 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 (previously filed as Exhibit 10.15 to our Annual Report on Form 10-K filed on March 15, 2001 and incorporated herein by reference).

10.16 Second Amendment, dated November 22, 1999, to Loan Agreement dated April 29, 1999, by and among Western Gas Resources, Inc. and NationsBank, as agent, and the Lenders. †

10.17 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 (previously filed as Exhibit 10.23 to our Quarterly Report on Form 10-Q filed on May 12, 2000 and incorporated herein by reference).

10.18 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 (previously filed as Exhibit 10.25 to our Quarterly Report on Form 10-Q filed on November 13, 2000 and incorporated herein by reference).

10.19 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 (previously filed as Exhibit 10.19 to our Annual Report on Form 10-Kfiled on March 15, 2001 and incorporated herein by reference).

10.20 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 (previously filed as Exhibit 10.24 to our Quarterly Report on Form 10-Q filed on May 14, 2001 and incorporated herein by reference).

10.21 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 (previously filed as Exhibit 10.25 to our Annual Report on Form 10-K filed on March 15, 2002 and incorporated herein by reference).

10.22 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 (previously filed as Exhibit 10.26 to our Quarterly Report on Form 10-Q filed on May 14, 2002 and incorporated herein by reference).

10.23 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 (previously filed as Exhibit 10.28 to our Quarterly Report on Form 10-Q filed on May 14, 2002 and incorporated herein by reference).

10.24 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 (previously filed as Exhibit 10.28 to our Annual Report on Form 10-K filed on March 24, 2003 and incorporated by reference herein).

10.25 Credit Agreement, dated as of April 24, 2003, among Western Gas Resources, Inc., as Borrower, Bank of America, N.A., as Administrative Agent and L/C Issuer, Bank One, NA and Fleet National Bank, as Co-Syndication Agents, The Royal Bank of Scotland plc and Wachovia Bank, National Association, as Co-Documentation Agents, and the Other Lenders Party Thereto (previously filed as Exhibit 10.2 to our Quarterly Report on Form 10-Q filed on May 13, 2003 and incorporated by reference herein).

10.26 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 (previously filed as Exhibit 10.26 to our Quarterly Report on Form 10-Q filed on May 14, 2001 and incorporated herein by reference).

10.27 Intercreditor Agreement, dated as of April 24, 2003, by and among the banks (as defined therein), Bank of America, N.A., as Administrative Agent for the banks and The Prudential Insurance Company of America, Pruco Life Insurance Company, ING Life Insurance & Annuity Company and Prudential Investment Management, Inc., consented to agreed by Western Gas Resources, Inc. and its subsidiaries listed therein (previously filed as Exhibit 10.3 to Western Gas Resources, Inc., 10-Q dated March 31, 2002 and incorporated herein by reference).

10.28 Restated Retirement Plan of Western Gas Resources, Inc., dated May 1, 2001, (previously filed as Exhibit 4.9 to our Registration Statement on Form S-8 filed on August 14, 2002 and incorporated herein by reference).

10.29 Western Gas Resources, Inc., 1997 Stock Option Plan.* †

10.30 First Amendment to the Western Gas Resources, Inc. 1997 Stock Option Plan. * †

10.31 Second Amendment to the Western Gas Resources, Inc. 1997 Stock Option Plan. * †

10.32 Western Gas Resources, Inc., 1999 Stock Option Plan.* (Previously filed as Exhibit 4.7 to our Registration Statement on Form S-8, Registration No. 333-95255, filed on January 24, 2000 and incorporated herein by reference.)

10.33 First Amendment to the Western Gas Resources, Inc. 1999 Stock Option Plan. * †

10.34 Second Amendment to the Western Gas Resources, Inc. 1999 Stock Option Plan. * †

10.35 Western Gas Resources, Inc. 2002 Stock Option Plan. * †

10.36 First Amendment to the Western Gas Resources, Inc. 2002 Stock Option Plan. * †

10.37 Western Gas Resources, Inc. Non-Employee Director's Stock Option Plan.* (Previously filed as part of Exhibit 4.7 to our Registration Statement on Form S-8, Registration No. 333-95259, filed on January 24, 2000 and incorporated herein by reference.)

10.38 Western Gas Resources, Inc. 2002 Non-Employee Director's Stock Option Plan.* †

10.39 Stock Option Agreement, effective November 1, 2001, by and between Western Gas Resources, Inc. and Peter A. Dea (previously filed as Exhibit 99.1 to our Registration Statement on Form S-8 filed on December 21, 2002, and incorporated herein by reference).*

10.40 Agreement, dated November 1, 2001, by and between Western Gas Resources, Inc., and Lanny F. Outlaw (previously filed as Exhibit 10.7 to our Quarterly Report on Form 10-Q filed on November 13, 2001 and incorporated herein by reference).*

10.41 2001 Employment Agreement, dated June 14, 2001, by and between Western Gas Resources, Inc. and Edward A. Aabak, together with 2001 Indemnification Agreement.* †

10.42 2001 Employment Agreement, dated June 14, 2001, by and between Western Gas Resources, Inc. and John F. Chandler, together with 2001 Indemnification Agreement.* †

10.43 2001 Employment Agreement, dated October 15, 2001, by and between Western Gas Resources, Inc. and William J. Krysiak, together with 2001 Indemnification Agreement.* †

10.44 2001 Employment Agreement, dated June 14, 2001, by and between Western Gas Resources, Inc. and John C. Walter, together with 2001 Indemnification Agreement.* †

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.

31.1 Section 302 Certification of the Chief Executive Officer.

31.2 Section 302 Certification of the Chief Financial Officer.

32.1 Section 906 Certification of the Chief Executive Officer and Chief Financial Officer.

* Management contract or compensating plan or arrangement.
† Indicates exhibits filed with this Form 10-K.

(b) Reports on Form 8-K:

During the quarter ended December 31, 2003, we filed the following Current Reports on Form 8-K:

- Report filed on October 24, 2003, announcing settlement of litigation with Williams Production RMT Company.
- Report filed on November 7, 2003, announcing that the Company has called for redemption 700,000 outstanding shares of its $2.625 Cumulative Convertible Preferred Stock.
- Report furnished on November 12, 2003, announcing the Company's third quarter 2003 results.
- Report filed on December 22, 2003, announcing that the Company has called for redemption 800,000 outstanding shares of its $2.625 Cumulative Convertible Preferred Stock.

(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 9, 2004.

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/ PETER A. DEA Peter A. Dea	Chief Executive Officer, President and Director (Principal Executive Officer)	March 9, 2004
/s/ WILLIAM J. KRYSIAK William J. Krysiak	Executive Vice President -Chief Financial Officer (Principal Financial and Accounting Officer)	March 9, 2004
/s/ JAMES A. SENTY James A. Senty	Chairman of the Board	March 9, 2004
/s/ WALTER L. STONEHOCKER Walter L. Stonehocker	Vice Chairman of the Board	March 9, 2004
/s/ DEAN PHILLIPS Dean Phillips	Director	March 9, 2004
/s/ JOSEPH E. REID Joseph E. Reid	Director	March 9, 2004
/s/ RICHARD B. ROBINSON Richard B. Robinson	Director	March 9, 2004
/s/ BILL M. SANDERSON Bill M. Sanderson	Director	March 9, 2004
/s/ WARD SAUVAGE Ward Sauvage	Director	March 9, 2004
/s/ BRION G. WISE Brion G. Wise	Director	March 9, 2004

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

	Year Ended December 31,		
	2003	2002	2001
Net income	$ 84,219	$ 50,589	$ 95,637
Add income items that do not affect operating cash flows:			
Depreciation, depletion and amortization	73,906	77,005	64,162
Deferred income taxes	49,326	19,614	42,815
Distributions less than equity income, net	1,076	(2,906)	(29)
(Gain) Loss on sale of property and equipment	(156)	948	(10,748)
Non-cash change in fair value of derivatives	(1,235)	13,788	(19,906)
Compensation expenses from re-priced stock options	94	224	170
Cumulative effect of change in accounting principle	6,724	-	-
Other non-cash items, net	1,712	1,809	1,405
Cash flow before working capital adjustments	$ 215,666	$ 161,071	$ 173,506

Glossary of Terms

Connected Reserves – Estimated future economic production associated with the wells currently producing and connected to Western's facilities for terms varying from one month, to their economic life (which in some cases will exceed fifty years).

Gas Processing – The separation of the components of natural gas by mechanical, refrigeration or cryogenic methods for the purpose of making salable liquid hydrocarbon products and also for the treating of the residue methane gas to meet required pipeline specifications. Salable gas liquid products include ethane, propane, butanes and natural gasoline.

Gas Throughput – The total gas moving through a pipeline system or processing facility.

Leasehold – The amount of acreage or property on which a company holds contractual drilling and legal rights for minerals such as natural gas and oil.

Natural Gas Liquids (NGLs) – Those hydrocarbons that go from a gaseous state in reservoir conditions to a liquid state at the surface in gas processing plants. Natural gas liquids include ethane, propane, butanes and natural gasoline.

Possible Reserves – Those unproved quantities of natural gas and/or oil which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves.

Probable Reserves – Those unproved quantities of natural gas and/or oil which analysis of geological and engineering data suggests are at least 50 percent likely to be recoverable.

Proved Reserves – Those quantities of natural gas and/or oil, which by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves included Proved Developed Producing ("PDP"), Proved Developed Non-producing ("PDNP") and Proved Undeveloped ("PUD").

Unconventional Natural Gas – Natural gas reservoirs that occur in coal seams, low permeability or 'tite' gas sands and shales. They typically cover large areas and often lack the apparent traps of conventional reservoirs.

Units of Measure

Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
Tcf	Trillion cubic feet
MMcfd	Million cubic feet per day
Bcfd	Billion cubic feet per day
MMcfe	Million cubic feet of gas equivalent
Bcfe	Billion cubic feet of gas equivalent
Tcfe	Trillion cubic feet of gas equivalent