QUESTAR CORP
Form 10-K
March 07, 2005

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2004

OR

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

FOR THE TRANSITION PERIOD FROM TO
Commission File No. 1-8796

QUESTAR CORPORATION

(Exact name of registrant as specified in its charter)

State of Utah	**87-0407509**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
180 East 100 South, P.O. Box 45433, Salt Lake City, Utah	**84145-0433**
(Address of principal executive offices)	(Zip code)

Registrant's telephone number, including area code: **(801) 324-5000**

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:

Title of each class	Name of each exchange on which registered
Common Stock, Without Par Value, with Common Stock Purchase Rights	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:

None

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

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

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

Aggregate market value of the voting common equity held by non-affiliates of the Registrant computed by reference to the price at which the common equity was last sold as of the last business day of the Registrant's most recently completed second quarter (June 30, 2004) $3,227,858,281.

On February 28, 2005, 84,701,901 shares of the registrant's common stock, without par value, were outstanding.

Documents Incorporated by Reference. Portions of the definitive Proxy Statement for the 2005 Annual Meeting of Stockholders are incorporated by reference into Part III. The sections of the Proxy Statement labeled "Committee Report on Executive Compensation" and "Cumulative Total Shareholder Return" are expressly not incorporated into this document.

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FORWARD-LOOKING STATEMENTS

This report includes "forward-looking statements" within the meaning of Section 27(a) of the Securities Act of 1933, as amended, and Section 21(e) of the Securities Exchange Act of 1934 as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding the Company's future financial position, business strategy, budgets, projected costs and plans and objectives of management for future operations, are forward-looking statements. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as "may," "will," "could," "expect," "intend," "project," "estimate," "anticipate," "believe," "forecast," or "continue" or the negative thereof or variations thereon or similar terminology. Although these statements are made in good faith and are reasonable representations of Questar Corporation's (Questar or the Company) expected performance at the time, actual results may vary from management's stated expectations and projections due to a variety of factors.

Important assumptions and other significant factors that could cause actual results to differ materially from those expressed or implied in forward-looking statements include:

Questar subsidiaries find, produce, and sell natural gas, oil and NGL. Natural gas, oil and NGL prices are volatile and, therefore, Questar revenues, cash flow and earnings can be volatile. The Company cannot predict future natural gas, oil and NGL price movements, which are subject to forces beyond our control such as:

- Domestic and foreign supply of natural gas and oil;
- Regional basis due to pipeline-capacity constraints;
- Domestic and global economic conditions;
- Weather;
- Domestic and foreign government regulations;
- The price and availability of alternative fuels;
- The price and availability of drilling rigs and other materials and services.

The Company uses financial contracts to hedge its exposure to volatile energy prices and to protect cash flow, returns on capital, net income and credit ratings from downward commodity-price movements. While hedging reduces the impact of declining prices, it may also limit future revenues from favorable price movements. Questar believes the Company's regulated businesses interstate natural gas transmission and retail gas distribution and its Wexpro subsidiary generate revenues that are not significantly sensitive to short-term fluctuations in energy prices.

Questar's profitability depends not only on prevailing prices for natural gas and oil, but also the Company's ability to find, develop and acquire gas and oil reserves that are economically recoverable. Substantial capital expenditures are required to find, develop and acquire gas and oil reserves to replace those depleted by production.

Questar Exploration and Production's proved natural gas and oil-reserve estimates are prepared annually by independent reservoir-engineering consultants. Gas and oil-reserve estimates are subject to numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and timing of development expenditures. The accuracy of these estimates depends on the quality of available data and on engineering and geological interpretation and judgment. Reserve estimates are imprecise and will change as additional information becomes available. Estimates of economically recoverable reserves and future net cash flows prepared by different engineers, or by the same engineers at different times may vary significantly. 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 proved reserves and the present value of those reserves are based upon certain assumptions about production levels, prices and costs, which may change. The volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The meaningfulness of such estimates depends on the accuracy of the assumptions upon which they were based. Actual results may differ materially from the estimated results.

Drilling is a high-risk activity. Operating risks include: blow-outs; fire; unexpected drilling conditions such as uncontrollable flows of gas, oil, formation water or drilling fluids; abandonment costs; explosions; pipe, cement or casing failures; oil spills; natural gas leaks; pipeline ruptures; and discharges of toxic gases. The Company could incur substantial losses as a result of injury or loss of life; environmental damage;

destruction of property; fines; or curtailment of operations. The Company maintains insurance against some, but not all, of these potential risks and losses.

Questar and its subsidiaries are subject to federal, state and local environmental, health and safety laws and regulations. Environmental laws and regulations are complex, change frequently and tend to become more onerous over time. In addition to the costs of compliance, the Company may incur substantial costs to take corrective actions at both owned and previously owned facilities. Accidental spills and leaks requiring cleanup may occur in the ordinary course of business. As standards change, the Company may incur significant costs in cases where past operations followed practices that were considered acceptable at the time but that now require remedial work to meet current standards. Failure to comply with these laws and regulations may result in fines, significant costs for remedial activities, or injunctions.

Questar and its subsidiaries must comply with numerous and complex regulations governing their activities on federal and state lands in the Rocky Mountain region, notably the National Environmental Policy Act, the Endangered Species Act, and the National Historic Preservation Act. Federal and state agencies frequently impose conditions on the Company's activities. These restrictions tend to become more stringent over time, and can limit or prevent the Company from exploring for, finding and producing natural gas and oil on its Rockies leasehold. Certain environmental groups oppose drilling on some of the Company's federal and state leases.

Questar Pipeline's natural gas-transmission and storage operations are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. The FERC has authority to: (1) set rates for natural gas transmission, storage, and related services; (2) set rules governing business relationships between the pipeline subsidiary and its affiliates; (3) approve new pipeline and storage-facility construction; and (4) establish policies and procedures for accounting, purchase, sale, abandonment and other activities. FERC policies may adversely affect Questar Pipeline profitability.

Questar Gas's natural gas-distribution business is regulated by the Public Service Commission of Utah (PSCU) and the Public Service Commission of Wyoming (PSCW). These commissions set rates for distribution services and establish policies and procedures for services, accounting, purchase, sale and other activities. PSCU and PSCW policies may adversely affect Questar Gas profitability.

Both Questar Pipeline and Questar Gas must incur significant costs to comply with new federal pipeline-safety regulations enacted in December 2002. Questar Pipeline and Questar Gas may also be affected by possible future regulations requiring the tracking, reporting and reduction of greenhouse-gas emissions.

Questar results may also be negatively affected by: changes in general economic conditions; changes in regulation; availability and economic viability of gas and oil properties for sale or exploration; creditworthiness of counterparties; rate of inflation and interest rates; assumptions used in business combinations; weather and natural disasters; changes in customers' credit ratings; competition from other forms of energy, other pipelines and storage facilities; effects of accounting policies issued periodically by accounting standard-setting bodies; terrorist attacks or acts of war; changes in the business or financial condition of the Company; changes in credit ratings; and availability of financing for Questar and its subsidiaries.

FORM 10-K
ANNUAL REPORT, 2004

PART I

ITEM 1. BUSINESS.

General

The registrant, Questar Corporation, is a natural gas-focused energy company with three principal lines of business gas and oil exploration and production, interstate gas transmission, and retail-gas distribution. Questar Market Resources (Market Resources) subsidiaries engage in gas and oil exploration, development and production, gas gathering and processing, wholesale gas and oil marketing, and gas storage. Questar Pipeline Company (Questar Pipeline) provides interstate natural gas transmission, storage and gas-processing and treating services. Questar Gas Company (Questar Gas) conducts retail natural gas distribution. In addition, corporate and other operations include other services and activities.

Questar was organized in 1984 and became a publicly held entity when the shareholders of Questar Gas (then known as Mountain Fuel Supply Company) approved a corporate reorganization. Questar was created to provide organizational and financial flexibility and to achieve a more clearly defined separation of utility and nonutility activities. Questar is a holding company, as that term is defined in the Public Utility Holding Company Act of 1935, because Questar Gas is a natural gas utility. Questar, however, qualifies for and claims an exemption from provisions of the act applicable to registered holding companies.

Market Resources is a subholding company that owns Questar Exploration and Production Company (Questar E&P), Wexpro Company (Wexpro), Questar Gas Management Company (Gas Management) and Questar Energy Trading Company (Energy Trading). Questar Pipeline and Questar Gas are the Company's two principal regulated subsidiaries.

Questar conducts most of its operations through subsidiaries. The parent-holding company performs certain management, legal, tax, administrative and other services for its subsidiaries. The corporate-organization structure and major subsidiaries are summarized below.

See Note 17 in Item 8 of this report for financial information concerning Questar's lines of business that contribute 10% or more of consolidated revenues.

Glossary of Commonly Used Terms

bbl	Barrel, which is equal to 42 United States gallons and is a common unit of measurement of crude oil.
basis	The difference between a reference or benchmark-commodity price and the corresponding sales price at various regional sales points.
bcf	One billion cubic feet, a common unit of measurement of natural gas.
bcfe	One billion cubic feet of natural gas equivalent. Oil volume is converted to natural gas equivalent using the ratio of one barrel of crude oil to 6,000 cubic feet of natural gas.
Btu	One British thermal unit a measure of the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit.
cash-flow hedge	A derivative instrument that complies with Statement of Financial Accounting Standards (SFAS) 133, as amended, and is used to reduce the exposure to variability in cash flows from the forecasted physical sale of gas and oil production whereby the gains (losses) on the derivative transaction are anticipated to offset the losses (gains) on the forecasted physical sale.

cf	Cubic foot is a common unit of gas measurement. One standard cubic foot equals the volume of gas in one cubic foot measured at standard conditions a temperature of 60 degrees Fahrenheit and a pressure of 30 inches of mercury (approximately 14.73 pounds per square inch).
development well	A well drilled into a known producing formation in a previously discovered field.
dew point	A specific temperature and pressure at which hydrocarbons condense to form a liquid.
dry hole	A well drilled and found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of production exceed expenses and taxes.
dth	Decatherms or ten therms. One dth equals one million Btu or approximately one Mcf.
exploratory well	A well drilled into a previously untested geologic prospect to determine the presence of gas or oil.
finding costs	Finding costs are the sum of costs incurred for gas and oil exploration and development activities; including leasehold acquisitions, seismic, geological and geophysical, development and exploration drilling, and asset-retirement obligations for a given period, divided by the total amount of estimated net-proved reserves added through discoveries, positive and negative revisions of previous estimates, and purchases in-place for the same period. The Company expresses finding costs in dollars per Mcfe averaged over a five-year period. See Note 19 included in Item 8 of this report for additional details.
futures contract	An exchange-traded legal contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price.
gross	"Gross" natural gas and oil wells or "gross" acres equal the total number of wells or acres in which the Company has a working interest.
heating-degree days	A measure of the number of degrees the average-daily outside temperature is below 65 degrees Fahrenheit.
hedging	The use of derivative-commodity and interest-rate instruments to reduce financial exposure to commodity-price and interest-rate volatility.
Mbbl	One thousand barrels.
Mcf	One thousand cubic feet.
Mcfe	One thousand cubic feet of natural gas equivalents. Oil volume is converted to natural gas equivalent using the ratio of one barrel of crude oil to 6,000 cubic feet of natural gas.
Mdth	One thousand decatherms.
Mdthe	One thousand decatherm equivalents. Oil volume is converted to natural gas equivalent using the ratio of one barrel of crude oil to 6,000 cubic feet of natural gas.
MMbbl	One million barrels.
MMBtu	One million British thermal units.
MMcf	One million cubic feet.
MMcfe	One million cubic feet of natural gas equivalents.
MMdth	One million decatherms.
MMgal	One million U. S. gallons.
natural gas	All references to "gas" in this report refer to natural gas.

natural gas liquids (NGL)	Liquid hydrocarbons that are extracted and separated from the natural gas stream. NGL products include ethane, propane, butane, natural gasoline and heavier hydrocarbons.
net	Net gas and oil wells or net acres are determined by the sum of the fractional ownership working interest the Company has in those gross wells or acres.
production-replacement ratio	The production-replacement ratio is calculated by dividing the net-proved reserves added through discoveries, positive and negative revisions of previous estimates, and purchases and sales in-place for a given period by the production for the same period, expressed as a percentage. The production-replacement ratio is typically reported on an annual basis divided by production.
proved reserves	Those quantities of natural gas, crude oil, condensate, and NGL on a net-revenue-interest basis, which geological and engineering data demonstrate with reasonable certainty to be recoverable under existing economic and operating conditions. See 17 C.F.R. Section 4-10(a)(2i)(2ii)(2iii) for a complete definition.
proved-developed reserves	Reserves that include proved developed-producing reserves and proved-developed behind-pipe reserves. See 17 C.F.R. Section 4-10(a)(3).
proved-developed-producing reserves	Reserves expected to be recovered from existing completion intervals in existing wells.
proved-undeveloped reserves	Reserves expected to be recovered from new wells on proved-undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. See 17 C.F.R. Section 4-10(a)(4).
reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
wet gas	Unprocessed natural gas that contains a mixture of heavier hydrocarbons including ethane, propane, butane, and natural gasoline.
working interest	An interest that gives the owner the right to drill, produce, and conduct operating activities on a property and receive a share of any production.

SEC Filings and Website Information

Questar, Market Resources, Questar Gas and Questar Pipeline file annual, quarterly, and current reports with the Securities and Exchange Commission (SEC). Questar also regularly files proxy statements and other documents with the SEC. Investors can read and copy any materials filed with the SEC at its Public Reference Room at 450 Fifth Street, N.W., Washington, D.C. 20549, and can obtain information about the operations of the Public Reference Room by calling the SEC at 1-800-SEC-0300. The SEC also maintains a website that contains information filed electronically that can be accessed over the Internet at www.sec.gov.

Investors can also access financial and other information for Questar at the Company's website at www.questar.com. Questar's website contains Statements of Responsibility for Board Committees, Corporate Governance Guidelines and its Business Ethics Policy.

Questar and each of its reporting subsidiaries make available, free of charge, through the website copies of Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to such reports and all reports filed by executive officers and directors under Section 16 of the Exchange Act reporting transactions in Questar securities. Access to these reports is provided as soon as reasonably practicable after such reports are electronically filed with the commission.

Narrative Description of Business

The Company has three major subsidiaries Market Resources, Questar Pipeline and Questar Gas. The following description of each subsidiary's business should be read in conjunction with Item 7. of this report.

Market Resources, General

Market Resources is Questar's primary growth driver. Market Resources has four major subsidiaries: Questar E&P acquires, explores for, develops and produces gas and oil; Wexpro manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas; Gas Management provides gas-gathering and processing services for affiliates and third parties; and Energy Trading markets equity and third-party gas and oil, provides risk-management services, and through its wholly owned limited liability company (LLC), Clear Creek Storage Company, LLC, owns and operates an underground gas-storage reservoir.

Questar E&P, General

Questar E&P operates in two core areas the Rocky Mountain region of Wyoming, Utah and Colorado and the Midcontinent region of Oklahoma, Texas and Louisiana. The company has a large inventory of identified development-drilling locations primarily at properties near Pinedale, Wyoming, and in the Uinta Basin of Utah. The company continues to conduct exploratory drilling to determine commerciality of its inventory of undeveloped leaseholds located primarily in the Rocky Mountain region, including assessment of deeper reservoirs beneath currently producing horizons. In the Midcontinent, Questar E&P has several active development projects, including an ongoing coalbed methane-development project in eastern Oklahoma and a tight-sands gas-development project in northwest Louisiana. Questar E&P seeks to maintain geographical and geological diversity with its two core regions. The company has in the past and may in the future pursue acquisition of producing properties through purchase of assets or corporate entities to expand its presence in its core areas or create a new core area.

Questar E&P increased year-end 2004 proved reserves 24% to 1,434 bcfe versus 1,159 bcfe at the end of 2003. Reserve additions included a 295 bcfe net increase at Pinedale related primarily to the approval of 20-acre well spacing.

Questar E&P's primary focus is natural gas. Natural gas comprised about 88.6% of Questar E&P's proved reserves. Approximately 56% of year-end 2004 total-proved reserves were classified as proved developed producing. The largest concentration of proved-undeveloped reserves is at the Pinedale development project, where approximately 541 bcfe are classified as proved undeveloped.

E&P, Risk Management

Questar E&P focuses primarily on lower-risk development drilling. In addition Market Resources has established policies and procedures for managing commodity-price risks through the use of derivatives. Market Resources hedges commodity prices to support credit ratings and to protect returns on invested capital, cash flow and earnings from downward movements in commodity prices. However, these arrangements usually limit future gains from favorable price movements. Market Resources may hedge up to 100% of its production from proved-developed reserves when commodity prices are attractive. Market Resources also manages market-access risk by building the necessary infrastructure, particularly gathering and processing facilities, to move company production to an interstate pipeline. See Item 7A. for more information.

The availability of regional pipeline capacity can also significantly affect gas prices. The Rocky Mountain region is the fastest growing major producing region in the United States. Regional gas production exceeds regional gas consumption, particularly during the nonheating season. Only about 20% of the gas produced in the Rockies is consumed by local markets. When Rockies production exceeds available pipeline capacity, Rockies basis the difference between gas prices at the Henry Hub (the national market benchmark) and sales prices in the Rockies widens, resulting in lower realized prices for producers. The expansion of the Kern River Pipeline in May 2003 added 0.9 bcf of daily capacity from the Rocky Mountain area to markets in the western U.S. This expansion helped alleviate a transportation shortfall that adversely affected Rockies gas prices though much of 2002 and the first half of 2003. The start-up in 2005 of a new 0.56-bcf-per-day pipeline, connecting Cheyenne, Wyoming to Greensburg, Kansas, may reduce basis risk for Rockies producers but also increase basis risk for Midcontinent producers.

E&P, Competition and Customers

Questar E&P faces competition in every part of its business, including the acquisition of reserves and leases. Its longer-term growth strategy depends, in part, on its ability to purchase reasonably priced reserves and develop them in a low-cost and efficient manner. Competition is particularly intense when prices are high, as has been the case in recent years.

Questar E&P, through Energy Trading, sells natural gas production to a variety of customers, including pipelines, gas-marketing firms, industrial users and local-distribution companies. It regularly evaluates counterparty credit and may require financial guarantees from parties that fail to meet its credit criteria. Energy Trading sells company crude-oil production to refiners, remarketers and other companies, including some with pipeline facilities near company producing properties. In the event pipeline facilities are not available, Energy Trading transports crude oil by truck to storage, refining or pipeline facilities.

E&P, Regulation

Questar E&P's operations are subject to various government controls and regulation at the federal, state and local levels. Questar E&P must obtain permits to drill and produce; maintain bonding requirements to drill and operate wells; submit and implement spill-prevention plans; and file notices relating to the presence, use, and release of specified contaminants incidental to gas and oil production. Questar E&P is also subject to various conservation matters, including the regulation of the size of drilling and spacing units, the number of wells that may be drilled in a unit and the unitization or pooling of gas and oil properties.

Most Questar E&P leases in the Rocky Mountain area are granted by the federal government and administered by federal agencies. Development of Pinedale leasehold acreage is subject to the terms of certain winter-drilling restrictions. During the last two years, Questar E&P has been working with federal and state officials in Wyoming to obtain authorization for limited winter-drilling activities and has developed innovative measures, such as drilling multiple wells from a single location, to minimize the impact of its activities on wildlife and the habitat. The presence of wildlife and potential endangered species could limit access to public lands. Various wildlife species inhabit Market Resources leaseholds at Pinedale and in other areas. Current federal regulations restrict activities during certain times of the year on portions of Market Resources leaseholds due to wildlife activity and/or habitat. Some species that are known to be present may be listed under federal law as endangered or threatened. Such listing could have a material impact on access to Market Resources leaseholds in certain areas or during periods when the particular species is present.

Wexpro, General

Wexpro has generated steady growth and predictable earnings through a business model that is unique in the energy industry. Wexpro develops gas and oil on certain producing properties for Questar Gas under the terms of a comprehensive agreement, the Wexpro Agreement. Under the Wexpro Agreement, Wexpro recovers its costs plus a return on its investment. See Note 15 in Item 8 of this report for more information on the Wexpro Agreement.

Wexpro natural gas production is delivered to Questar Gas at a price equal to Wexpro's cost-of-service. Wexpro production and operated reserves are not included in Questar E&P production and reserves, which are referred to as nonregulated production and reserves. Wexpro cost-of-service gas, plus the gas attributable to royalty-interest owners, satisfied 47% of Questar Gas's system requirements during 2004. The average wellhead cost (net of revenue credits) of Questar Gas's cost-of-service gas in 2004 was $2.71 per dth, which was lower than Questar Gas's average cost for field-purchased gas.

Wexpro Regulations

Wexpro's gas and oil-development and production activities are subject to the same type of regulation as Questar E&P. Wexpro is also subject to oversight by the Utah Division of Public Utilities. The division retains an outside consultant to assess the prudence of Wexpro's activities.

Wexpro also owns oil-producing properties. Under terms of the Wexpro Agreement, revenues from crude-oil sales offset operating expenses and provide Wexpro with a return on its investment. Surplus revenues, after recovery of expenses and Wexpro's return on investment, are divided between Wexpro (46%) and Questar Gas (54%).

Gas Gathering and Processing, General

Gas Management provides gas-gathering and processing services to affiliates and third-party producers, primarily in the Rocky Mountain region. Gas Management also owns 50% of Rendezvous Gas Services, LLC (Rendezvous), a joint venture that operates gas-gathering facilities in western Wyoming. Rendezvous gathers natural gas for Pinedale Anticline and Jonah producers for delivery to various interstate pipelines. Rendezvous plans to build a new gathering line from Black's Fork plant to a connection with the Kern River Pipeline. Under a contract with Questar Gas, Gas Management gathers cost-of-service volumes produced from properties operated by Wexpro.

Gas Management's processing margins are based on the difference between the market price for natural gas and the market value of the NGL extracted from the gas stream (commonly referred to as the "frac spread"). Gas Management may hedge NGL prices to protect processing margins. To reduce margin risk Gas Management has restructured many of its processing agreements with producers from "keep-whole" contracts to "fee-based" contracts. (A keep-whole contract insulates producers from NGL-and gas-price risk while a fee-based contract eliminates commodity-price risk for the plant owner.)

Gas and Oil Marketing and Trading, Risk Management and Underground Storage, General

Energy Trading markets natural gas, oil and NGL. It combines gas volumes purchased from third parties and equity production (production from affiliates) to build a flexible and reliable portfolio. As a wholesale-marketing entity, Energy Trading concentrates on markets in the Pacific Northwest, Rocky Mountains and Midwest that are close to reserves owned by affiliates or accessible by major pipelines. It contracts for firm-transportation capacity on pipelines and firm-storage capacity at Clay Basin (a large baseload-storage facility owned by Questar Pipeline).

Energy Trading uses derivatives to manage commodity-price risk. Energy Trading primarily uses fixed-price swaps to secure a known price for a specific volume of company production. Energy Trading does not engage in speculative hedging transactions. See Notes 1 and 10 included in Item 8 and Item 7A of this report for additional information relating to hedging activities.

Energy Trading pays Questar E&P index prices for production volumes on which the latter calculates and pays royalties. Energy Trading then resells such volumes and bears profit-and-loss risk. In addition to contracting for storage capacity at Clay Basin, Energy Trading, through its wholly owned subsidiary Clear Creek Storage Company, LLC, owns and operates an underground gas-storage reservoir in southwestern Wyoming. It uses owned and leased-storage capacity together with firm-transportation capacity to take advantage of price differentials and arbitrage opportunities.

Questar Pipeline, General

Questar Pipeline is an interstate pipeline company that provides natural gas-transportation and underground storage services in the Rocky Mountain states of Utah, Wyoming and Colorado. As a "natural gas company" under the Natural Gas Act of 1938, Questar Pipeline and certain subsidiary pipeline companies are regulated by the FERC as to rates and charges for storage and transportation of natural gas in interstate commerce, construction of new facilities, and extensions or abandonments of service and facilities, accounting and other activities.

Questar Pipeline and its subsidiaries own 2,497 miles of interstate pipeline with total daily capacity of 2,892 Mdth. Questar Pipeline's core-transmission system is strategically located in the Rocky Mountain area near large reserves of natural gas in six major Rocky Mountain producing areas. Questar Pipeline transports natural gas from these producing areas to other major pipeline systems and to the Questar Gas distribution system. In addition to this core system, Questar Pipeline, through a subsidiary, owns and operates the Southern Trails Pipeline, a 488-mile line that extends from the Blanco hub in the San Juan Basin to just inside the California state line.

Questar Pipeline owns and operates the Clay Basin storage facility, the largest underground- storage reservoir in the Rocky Mountain region. Through a subsidiary, Questar Pipeline also owns gathering lines and a processing plant in Price, Utah, which provides heat-content-management services for Questar Gas and carbon-dioxide processing for third parties.

Questar Pipeline, Risk Management

Questar Pipeline faces risks from changes in regulatory practice, credit risk of firm-capacity holders, damage to pipelines from third parties or natural causes, and bypass by other pipelines or gathering lines In its storage operations, Questar Pipeline faces risks associated with performance of storage reservoirs or storage facilities.

Questar Pipeline mitigates these risks by actively participating in FERC regulatory proceedings, monitoring customer credit ratings and exercising its tariff rights including the requirement of prepayments, marking underground pipelines, monitoring construction activities near its facilities, and monitoring the performance of underground-storage facilities.

Questar Pipeline faces risk of recontracting firm capacity as contract terms expire. Questar Pipeline's transportation system is nearly fully subscribed and firm contracts had a weighted-average remaining life of 9.3 years as of December 31, 2004. All of Questar Pipeline storage capacity is fully subscribed with a weighted-average remaining life of 7.4 years as of December 31, 2004.

Questar Pipeline, Customers, Growth and Competition

Questar Gas remains Questar Pipeline's largest single transportation customer. During 2004, Questar Pipeline transported 116.5 MMdth for Questar Gas compared to 105.7 MMdth in 2003. Questar Gas has reserved firm-transportation capacity of 951 Mdth per day under long-term contracts, or about 60% of Questar Pipeline's reserved capacity, during the three coldest months of the year. Questar Pipeline's primary transportation agreement with Questar Gas will expire on June 30, 2017.

Questar Pipeline also transported 220.5 MMdth for nonaffiliated customers to pipelines owned by Kern River Pipeline, Northwest Pipeline, Colorado Interstate Gas, TransColorado, WIC and other systems. Questar Pipeline may be adversely affected by proposals before the FERC to establish natural gas-quality standards, specifically for hydrocarbon dew point. Questar Pipeline's tariff provides a higher hydrocarbon dew-point specification than other systems, which requires less processing by producers before natural gas volumes are delivered into Questar Pipeline's system. Other interstate pipelines require lower dew-point gas. As a consequence, Questar Pipeline must incur higher costs to blend lower dew-point-processed gas with wet gas and in some instances isolate processed gas for delivery to other pipelines. In effect, Questar Pipeline currently provides a bundled gas-transportation and dew-point-management service for its shippers. Questar Pipeline may need to restructure its tariff to unbundle these services.

During 2005, Questar Pipeline will expand its southern system in central Utah. This expansion, scheduled to be in service by the fourth quarter of the year, will add 102 Mdth of daily capacity under long-term contracts. Questar Pipeline received FERC approval for the expansion in January 2005. During 2004 Questar Pipeline installed a lateral pipeline to a power plant near Mona, Utah. This lateral will be in service during the first quarter of 2005. These projects will add about $0.04 cents per share to 2006 earnings, the first full year of operations.

During 2003, Questar Pipeline increased its capacity for deliveries to Kern River by 150 Mdth per day through a new interconnect at Roberson Creek in southwestern Wyoming. Questar Pipeline also completed its Tie Line 112 expansion in late 2003. Questar Gas holds long-term contracts for 52 Mdth per day on this new line, which is expandable to 180 Mdth per day with additional compression. Tie Line 112 provided critical incremental supplies and operating flexibility during a period of record demand in early 2004.

Rocky Mountain producers, marketers and end-users seek capacity on transmission systems that move gas to California (Kern River), the Pacific Northwest (Northwest Pipeline) or Midwestern markets (WIC, Colorado Interstate Gas). Questar Pipeline provides access for many producers to these third-party pipelines. Some parties, including Gas Management, an affiliate of Questar Pipeline, are building gathering lines that allow producers to make direct connections to competing pipeline systems.

Questar Pipeline seeks to extend and expand its core pipeline and storage business. Questar Pipeline and other pipelines have proposed projects to connect Piceance Basin (northwest Colorado) gas supplies with pipelines moving gas east out of Wyoming. Questar Pipeline is conducting an open season to assess possible market support for these new projects. Questar Pipeline is also assessing the feasibility of a gas-storage project in western Wyoming.

In mid-2002 a Questar Pipeline subsidiary placed the eastern segment of the Southern Trails pipeline into service. The eastern segment extends from the San Juan basin to the California border. Capacity on this segment is fully committed under contracts that expire in mid-2008. Current market rates for transportation between these receipt and delivery points are less than current contract rates. When the existing contracts expire, Questar Pipeline's subsidiary may have to lower rates to recontract capacity on this pipeline, which would reduce revenues and earnings.

Questar Pipeline has thus far failed to secure long-term contracts for the western segment of Southern Trails, which extends from the California border to Long Beach, California. Questar Pipeline has been working with the Los Angeles Department of Water and Power (LADWP) to develop a gas pipeline to serve a power-generation facility. LADWP budgeted funds to acquire a gas pipeline and issued a request for proposal in October 2004. Questar Pipeline responded to this request with a proposal to complete conversion and sell the western segment to LADWP. On February 28, 2005, LADWP notified Questar Pipeline of its intent to pursue the proposal, although it is uncertain whether negotiations will be successful. Conversion of the segment and extension to LADWP's power-generation facilities will require significant additional investment on the order of $45 to $55 million.

Questar Pipeline, Regulation

FERC Order No. 2004, which defines standards of conduct for transmission providers, became effective on September 22, 2004. These rigorous new affiliate rules are designed to ensure that transmission-system employees function independently from employees of marketing and energy affiliates. In addition, a transmission provider must treat all transmission customers on a nondiscriminatory basis and will not be allowed to operate its transmission system to benefit its marketing or energy affiliates. Based on clarification from the FERC, Questar Pipeline has determined that Market Resources' affiliates, except Gas Management, are marketing or energy affiliates. Questar Gas is not an energy affiliate. Questar Pipeline and other Questar companies have adopted new procedures to comply with this order.

Questar Pipeline is required to comply with the Pipeline Safety Improvement Act of 2002. This act and rules issued by the Department of Transportation (DOT) require interstate pipelines and local-distribution companies to implement a 10-year program of risk analysis, pipeline assessment and remedial repair for transmission pipelines located in high-consequence areas such as population centers. Questar Pipeline filed a compliance plan with the FERC during 2004. Questar Pipeline estimates the annual compliance cost at $1 million, not including pipeline replacement, if necessary.

During the fourth quarter of 2004, Questar Pipeline received a FERC order in a case involving the annual Fuel Gas Reimbursement Percentage (FGRP). The FERC previously granted Questar Pipeline's request to increase the FGRP effective January 1, 2004. In its order, the FERC approved the FGRP but also ruled that Questar Pipeline is required to credit to transmission customers proceeds from selling natural gas liquids recovered from its dew-point facilities at the Kastler plant in northeastern Utah. See Item 7. of this report for additional information about the FGRP.

Clay Basin Storage Gas

Questar Pipeline continues to investigate a potential discrepancy of up to 9 bcf between the book volume of cushion gas at Clay Basin and cushion-gas volumes implied by pressure-survey data obtained in recent field tests. The current book volume of the cushion gas is 61.5 bcf with a value of $99.7 million. Questar Pipeline has not determined if any gas is missing from the reservoir. Analysis to date has not revealed any leaks or gas migration out of the reservoir. Additional reservoir tests and analysis, including reservoir modeling, are under way to identify the cause and may continue for several years. See Item 7. of this report.

Questar Gas, General

Questar Gas distributes natural gas as a public utility in Utah, southwestern Wyoming and a small portion of southeastern Idaho. As of December 31, 2004, Questar Gas was serving 794,117 sales and transportation customers. Questar Gas is the only nonmunicipal gas-distribution utility in Utah, where over 96% of its customers are located. Questar Gas has the necessary regulatory approvals to serve these areas granted by the PSCU and PSCW and the Public Utility Commission of Idaho. It also has long-term franchises granted by communities and counties within its service area.

Questar Gas, Growth

Questar Gas's growth is tied to the economic growth of Utah and southwestern Wyoming. It has over 90% of the load for residential space heating and water heating in Utah. During 2004, Questar Gas added 23,623 customers, a 3.1% increase.

Questar Gas, Risk Management

Questar Gas faces the same risks as other local-distribution companies. These risks include revenue variations based on seasonal changes in demand, sufficient gas supplies, declining residential usage per customer, adequate distribution facilities and adverse regulatory decisions. Questar Gas's sales to residential and commercial customers are seasonal, with a substantial portion of such sales made during the heating season. The typical residential customer in Utah (defined as a customer using 115 dth per year) consumes over 77% of total gas requirements in the coldest six months of the year. Questar Gas, however, has a weather-normalization mechanism for its general-service customers. This mechanism adjusts the nongas portion of a customer's monthly bill as the actual heating-degree days in the billing cycle are warmer or colder than normal. This mechanism reduces dramatic fluctuations in any given customer's monthly bill from year to year and reduces fluctuations in Questar Gas's gross margin.

Questar Gas minimizes its supply risks by owning natural gas-producing properties. During 2004, it satisfied 47% of its system requirements with the cost-of-service gas and associated royalty-interest volumes produced from such properties. Wexpro produces the gas from these properties, which is then gathered by Gas Management and transported by Questar Pipeline. Questar Gas had estimated proved cost-of-service natural gas reserves of 531.1 bcf as of year-end 2004 compared to 434.4 bcf a year earlier.

Questar Gas also has a balanced and diversified portfolio of gas-supply contracts for volumes produced in the Rocky Mountain states of Wyoming, Colorado, and Utah. Questar Gas has regulatory approval to include costs associated with hedging activities in its balancing account for pass-through treatment.

Questar Gas has designed its distribution system and annual gas-supply plan to handle design-day demand requirements. It periodically updates its design-day demand, the volume of gas that firm customers could use during extremely cold weather. For the 2004-05 heating season, Questar Gas used a design-day demand of 1,077 Mdth for firm-customers.

Questar Gas has long-term contracts with Questar Pipeline for transportation capacity and storage capacity at Clay Basin and three peak-day facilities. It also contracts to take deliveries at several locations on the Kern River Pipeline that runs through Utah.

During 2004, Questar Gas placed a new customer-information system in service, replacing a 30-year-old legacy system. The new system cost $20 million and should increase Questar Gas's efficiency, reduce technology costs and provide better information to customers.

Questar Gas, Regulation

As a public utility, Questar Gas is subject to the jurisdiction of the PSCU and PSCW. Natural gas sales and transportation services are made under rate schedules approved by the two regulatory commissions. Questar Gas is authorized to earn a return on equity of 11.2% in Utah and 11.83% in Wyoming. Both the PSCU and PSCW permit Questar Gas to recover gas costs through a balancing-account procedure and to reflect natural gas-price changes on a periodic, generally semi-annual, basis. Questar Gas has also received permission from the PSCU and PCSW to reflect in its gas costs specified costs associated with hedging contracts.

At year-end 2002, the PSCU issued an order in Questar Gas's general rate case approving a stipulation that reflected a test year primarily based on November 2002 rate base, expenses and customers, and changed its accounting for contributions in aid of construction.

On August 1, 2003, the Utah Supreme Court issued an order reversing an August 2000 decision made by the PSCU concerning certain natural gas-processing costs incurred by Questar Gas. The court ruled that the PSCU did not comply with its statutory responsibilities and regulatory procedures when approving a stipulation in Questar Gas's 1999 general-rate case. The stipulation permitted Questar Gas to collect $5.0 million per year, a portion of the processing costs, through May 2004. The Committee of Consumer Services, a Utah state agency, appealed the PSCU's decision because the PSCU did not explicitly address whether the costs were prudent.

As a result of the court's order, Questar Gas recorded a liability for a potential refund to gas-distribution customers. A total liability of $29.0 million, including $4.1 million recorded in the first nine months of 2004, reflects revenue received for processing costs and interest from June 1999 through September 2004.

On August 30, 2004, after hearings held in May 2004, the PSCU ruled that Questar Gas failed to prove prudence in contracting for gas processing in response to the changes in the heat content of its gas supply. The PSCU rejected the stipulation, denied the request for rate recovery and ordered the refund of costs previously collected in rates. Since Questar Gas had accrued a liability for the refund, the order did not have a material impact on earnings for the third quarter of 2004. In addition, the order did not have a material impact on the creditworthiness, cash flow or liquidity of Questar or Questar Gas. Questar Gas reduced its rates on September 1, 2004, to eliminate the collection of gas-processing costs and, on October 1, 2004, began refunding previously collected costs, plus interest, over a 12-month period as ordered by the PSCU. As of December 31, 2004, Questar Gas had a liability of $20.6 million of remaining refunds to customers.

On September 16, 2004, Questar Gas filed a petition with the PSCU for reconsideration or clarification of the August 30, 2004, order. On October 20, 2004, the PSCU declined to reconsider its order but clarified that its order did not preclude recovery of ongoing and certain past processing costs. Ongoing processing costs are approximately $6 million per year.

Questar Gas has requested ongoing rate coverage for gas-processing costs in its pass-through filings but is not currently collecting these costs in rates. The PSCU has conducted several technical conferences to determine how to resolve issues of managing the heat content of the gas supply. On January 31, 2005, Questar Gas filed a rate request with the PSCU to recover $5.7 million per year of gas-processing costs through its gas-balance account.

Questar Gas has significant relationships with affiliates that have allowed it to lower its costs and improve efficiency. These affiliate relationships, however, are subject to increased oversight by regulatory commissions for evidence of subsidization and above-market payments.

Questar Gas is subject to the requirements imposed by the Pipeline Safety Improvement Act of 2002 administered by the DOT. The act requires Questar to develop an integrity-management plan and assess on a recurring basis the integrity of its high-pressure lines in "high consequence" areas. Questar Gas estimates that it may be required to spend $4 to $5 million per year to comply with the new requirements. The PSCU has allowed Questar Gas to record incremental-operating costs to comply with this act as a regulatory asset until the next rate case or three years, whichever is sooner.

Questar Gas, Competition

Questar Gas is a public utility and currently has no direct competition from other distributors of natural gas for residential and commercial customers. It has historically enjoyed a favorable price comparison with other energy sources used by residential and commercial customers except coal and occasionally fuel oil. It provides transportation service to industrial customers that can buy volumes of gas directly from others. Questar Gas makes low margins on this transportation service, but could lose customers to Kern River.

Corporate and Other Operations

Historically, Questar's other operations included information-technology and communication services (Questar InfoComm); web-hosting and data centers (Consonus); commercial real-estate management (Interstate Land); and well-head gas analysis and automation, field compression and engine maintenance (Energy Services). During 2004, Questar reorganized these activities to refocus attention on primary business units. Questar has no plans to enlarge the scope of these activities. The Company reorganized its information-technology services to eliminate duplication and increase efficiency. The majority of information-technology employees and assets were transferred to the separate business units. Consonus has never fulfilled its business purpose and has significantly retrenched its operations. Interstate Land was merged with Questar InfoComm during 2004. Energy Services is focusing on well-head gas analysis and automation.

Environmental Matters

See Item 3. Legal Proceedings in this report for a discussion of the Company's environmental matters.

Employees

At January 1, 2005, the Company had 2,136 employees, including 563 in Market Resources, 173 in Questar Pipeline, 1,243 in Questar Gas, and 157 in corporate and other operations.

Executive Officers

The following individuals are serving as executive officers of the Company:

Name		**Primary Positions Held with the Company and Affiliates, Other Business Experience**
Keith O. Rattie	51	Chairman (May 2003); President (February 2001); Chief Executive Officer (May 2002); Director (February 2001); Chief Operating Officer (February 2001 to May 2002); Director, Questar affiliates (February 2001). Prior to coming to Questar, Mr. Rattie served as Vice President and Senior Vice President of the Coastal Corporation (from 1996 to January 2001).
Charles B. Stanley	46	Executive Vice President, Director Questar (November 2002); President, Chief Executive Officer and Director, Market Resources and Market Resources subsidiaries (November 2002); Senior Vice President, Questar (February 2002 to November 2002); Executive Vice President and Chief Operating Officer, Market Resources and Market Resources subsidiaries (February 2002 to November 2002). Prior to joining Questar, Mr. Stanley was President and Chief Executive Officer and Director, Coastal Gas International Co. (1995 to 2000); President and Chief Executive Officer of El Paso Oil and Gas Canada, Inc. (2000 to January 2002).
Alan K. Allred	54	Executive Vice President, Questar (May 2003); President and Chief Executive Officer and Director, Regulated Services and Questar Gas (May 2003); Chief Executive Officer and Director, Questar Pipeline (May 2003); President, Questar Pipeline (May 2003 to January 2005); Executive Vice President and Chief Operating Officer, Regulated Services, Questar Gas and Questar Pipeline (November 2002 to May 2003); Senior Vice President, Regulated Services, Questar Gas and Questar Pipeline (March 2002 to November 2002); Vice President, Business Development, Regulated Services, Questar Gas and Questar Pipeline (November 2000 to

Name		Primary Positions Held with the Company and Affiliates, Other Business Experience
		March 2002); Manager, Regulatory Affairs, Questar Gas and Questar Pipeline (October 1997 to November 2000).
R. Allan Bradley	53	President and Chief Operating Officer and Director, Questar Pipeline (January 2005); Senior Vice President, Questar (February 2005);. Prior to joining Questar, Mr. Bradley was Managing Director and founding member, Ventura Energy LLC (2002 to December 2004) and Senior Vice President, Coastal and El Paso affiliates (1990-2002).
Stephen E. Parks	53	Senior Vice President and Chief Financial Officer (March 2001); Chief Financial Officer (February 1996); Treasurer (May 1984 to March 2004); Vice President (February 1990 to March 2001); Vice President, Treasurer and Chief Financial Officer of all affiliates (at various dates beginning in May 1984); and Director Market Resources subsidiaries (at various dates beginning in May 1996).
Connie C. Holbrook	58	Senior Vice President (March 2001); Vice President (October 1984 to March 2001); Corporate Secretary (October 1984); General Counsel (April 1999); Corporate Secretary, Questar Gas and other affiliates (at various dates beginning in March 1982).
Glenn H. Robinson	54	Vice President, Questar, (May 2004); President and Chief Information Officer, Questar InfoComm (August 2000 to May 2004); Vice President and Chief Information Officer, Questar (August 2000 May 2004); Director, Questar InfoComm (August 2000); Vice President and Controller, Regulated Services (January 1999 to August 2000), Questar Gas (April 1991 to August 2000), and Questar Pipeline (September 1996 to August 2000).
Brent L. Adamson	53	Vice President, Ethics, Compliance and Audit (March 2002); Director, Audit (August 1982 to March 2002); Compliance Officer (March 1995 to March 2002).

There is no "family relationship" between any of the listed officers or between any of them and the Company's directors. The executive officers serve at the pleasure of the Board of Directors. There is no arrangement or understanding under which the officers were selected.

ITEM 2. PROPERTIES.

Exploration and Production

Reserves Questar E&P. The following table sets forth Questar E&P's estimated proved reserves, the estimated future net revenues from the reserves and the standardized measure of discounted net cash flows as of December 31, 2004. The U.S. reserves were collectively estimated by Ryder Scott Company; Netherland, Sewell & Associates, Inc., H. J. Gruy and Associates, Inc. and Malkewicz Hueni Associates Inc., independent reservoir-engineering consultants. Estimates of Canadian reserves were prepared by Gilbert Laustsen Jung Associates Ltd, and Sproule Associates Limited, independent reservoir engineers. Questar E&P does not have any long-term supply contracts with foreign governments or reserves of equity investees or of subsidiaries with a significant minority interest. All properties are located in the United States.

Estimated proved reserves		
Natural gas (bcf)		1,270.5
Oil and NGL (MMbbl)		27.2
Total proved reserves (bcfe)		1,434.0
Proved developed reserves (bcfe)		808.3
Estimated future net revenues before future income taxes (in thousands)(1)	$	5,599,487
Standardized measure of discounted net cash flows (in thousands)(2)	$	1,760,538

(1)

Estimated future net revenue represents estimated future gross revenue to be generated from the production of proved reserves, using average year-end 2004 prices of $5.50 per Mcf for natural gas

and $40.60 per bbl for oil and NGL combined, net of estimated production and development costs (but excluding the effects of general and administrative expenses; debt services; depreciation, depletion and amortization; and income tax expense).

(2)

The standardized measure of discounted net cash flows prepared by the Company represent the present value of estimated future net revenues after income taxes, discounted at 10%.

Estimates of proved reserves and future net revenues are made at year end, using sales prices estimated to be in effect as of the date of such reserve estimates and are held constant throughout the remaining life of the properties (except to the extent a contract specifically provides for escalation). Year-end prices do not include the effect of hedging. Estimated quantities of proved reserves and future net revenues are affected by natural gas and oil prices, which have fluctuated widely in recent years. There are numerous uncertainties inherent in estimating natural gas and oil reserves and their estimated values, including many factors beyond the control of the producer.

Questar E&P's reserve statistics for the years ended December 31, 2000, through 2004, are summarized below.

	Proved Gas and Oil Reserves (bcfe)*		
Year	**Year-End Reserves**	**Annual Production**	**Reserve Life (Years)**
2000	730.1	82.3	8.9
2001	1,184.4	85.6	13.8
2002	1,113.4	96.3	11.6
2003	1,158.7	92.8	12.5
2004	1,434.0	103.5	13.9

*

Does not include cost-of-service reserves managed, developed and produced by Wexpro for Questar Gas.

Finding costs measure the costs of finding, developing and acquiring new proved reserves. The production-replacement ratio measures company success at replacing production during a specific period. If the production-replacement ratio is greater than 100%, the Company added or replaced more reserves than it produced for the same period. These non-GAAP measures provide useful information to investors interested in analyzing Questar's performance, but may not be directly comparable with similar information disclosed by other gas and oil companies.

In 2004 gas and oil reserves increased 24%, after production and sales of producing properties, to 1,434 bcfe versus a 4% increase in 2003 to 1,159 bcfe. Questar E&P's production-replacement ratio was 366% in 2004 and 149% in 2003. Net reserve additions, revisions, purchases and sales in place totaled 379 bcfe in 2004 and 138 bcfe in 2003. Questar E&P's five-year average finding cost of proved reserves per Mcfe was $0.83, $0.84 and $0.85 in 2004, 2003 and 2002, respectively. The 66% increase in reserves at the Pinedale Anticline was attributable to the 20-acre downspacing.

Questar E&P's proved reserves by major operating areas at December 31, 2004 and 2003 follow.

	2004	**2004**	**2003**	**2003**
	(bcfe)		**(bcfe)**	
Rocky Mountains				
Pinedale Anticline	737.9	51%	443.2	38%
Uinta Basin	272.4	19%	303.3	26%
Other Rocky Mountains	137.2	10%	133.0	12%
Subtotal Rocky Mountains	1,147.5	80%	879.5	76%
Midcontinent	286.5	20%	279.2	24%
Total	1,434.0	100%	1,158.7	100%

2004	2004	2003	2003

Reserves Cost-of-Service. The following table sets forth (i) Questar Gas's estimated cost-of-service proved natural gas reserves (which are managed, developed and delivered by Wexpro under the terms of the settlement agreement); and (ii) Wexpro's proved-oil reserves (the income from which is shared with Questar Gas pursuant to the terms of the settlement agreement). The estimates were made by Wexpro's reservoir engineers as of December 31, 2004. All properties are located in the United States.

Estimated cost of service proved reserves	
Natural gas (bcf)	531.1
Oil (MMbbl)	4.2
Total proved reserves (bcfe)	556.3
Proved-developed reserves (bcfe)	428.4

Since the gas reserves operated by Wexpro are delivered to Questar Gas at cost of service, and any net income from oil properties remaining after recovery of expenses and Wexpro's contractual return on investment under the settlement agreement is divided between Wexpro and Questar Gas, SEC guidelines with respect to standard economic assumptions are not applicable. The SEC anticipated such potential difficulty and provides that companies may give appropriate recognition to differences arising because of the effect of the ratemaking process. Accordingly, Wexpro's reservoir engineers used a minimum producing rate or maximum well-life limit to determine the ultimate quantity of reserves attributable to each well.

Reference should be made to Note 19 included in Item 8 of this report for additional information pertaining to both the Questar E&P's proved reserves and the company's cost-of-service reserves as of the end of each of the last three years.

In addition to this filing, Questar E&P and Wexpro will each file estimated reserves as of December 31, 2004, with the Energy Information Administration in the Department of Energy on Form EIA-23. Although the companies use the same technical and economic assumptions when they prepare the EIA-23, they are obligated to report reserves for all wells they operate, not for all wells in which they have an interest, and to include the reserves attributable to other owners in such wells.

Production. The following table sets forth the net production volumes, the average sales prices per Mcf of gas, per barrel of oil and of NGL produced, and the production cost per Mcfe for the years ended December 31, 2004, 2003, and 2002, respectively. Production costs include direct-lifting costs (labor, repairs and maintenance, materials, supplies and workovers), administrative costs of production offices, insurance and property and severance taxes, but are exclusive of depreciation and depletion applicable to capitalized-lease acquisitions, exploration and development expenditures. Questar E&P's Canadian properties were sold in the last quarter of 2002.

	Year Ended December 31,		
	2004	2003	2002
United States (excluding cost-of-service activities)			
Volumes produced and sold			
Gas (bcf)	89.8	78.8	74.9
Oil and NGL (MMbbl)	2.3	2.3	2.3
Average realized price (including hedges)			
Gas (per Mcf)	$ 4.18	$ 3.62	$ 2.61
Oil and NGL (per bbl)	30.97	23.39	20.26
Production costs per Mcfe			
Lease-operating expense	$ 0.50	$ 0.49	$ 0.51
Production taxes	0.46	0.34	0.20
Production cost	$ 0.96	$ 0.83	$ 0.71

	Year Ended December 31,		
	2004	2003	2002
Canada (in U.S. dollars)			
Volumes produced and sold			

	Year Ended December 31,		
Gas (bcf)			4.8
Oil and NGL (MMbbl)			0.5
Average realized price (including hedges)			
Gas (per Mcf)			$ 2.22
Oil and NGL (per bbl)			21.03
Production costs per Mcfe			
Lease-operating expense			$ 0.92
Production cost			$ 0.92
Cost-of Service (Wexpro-managed)			
Volumes produced			
Gas (bcf)	38.8	40.1	41.2
Oil and NGL (MMbbl)	0.4	0.4	0.5

Productive Wells. The following table summarizes Market Resources' productive wells (including the cost-of-service wells managed by Wexpro) as of December 31, 2004. All of these wells are located in the United States.

		Gas	Oil	Total
Productive Wells	Gross	3,893	926	4,819
	Net	1,819.0	450.3	2,269.3

Although many of Market Resources' wells produce both gas and oil, a well is categorized as either a gas or an oil well based upon the ratio of gas to oil produced. Each gross well completed in more than one producing zone is counted as a single well. At the end of 2004, there were 63 gross wells with multiple completions.

Market Resources also holds numerous overriding-royalty interests in gas and oil wells, a portion of which is convertible to working interests after recovery of certain costs by third parties. After converting to working interests, these overriding-royalty interests will be included in Market Resources' gross and net-well count.

Leasehold Acres. The following table summarizes developed and undeveloped-leasehold acreage in which Market Resources owns a working interest as of December 31, 2004. "Undeveloped Acreage" includes (i) leasehold interests that already may have been classified as containing proved undeveloped reserves; and (ii) unleased mineral-interest acreage owned by the company. Excluded from the table is acreage in which Market Resources' interest is limited to royalty, overriding-royalty and other similar interests. All leasehold acres are located in the U.S.

Leasehold Acreage December 31, 2004

	Developed(1)		Undeveloped(2)		Total	
	Gross	Net	Gross	Net	Gross	Net
Arizona			480	450	480	450
Arkansas	31,720	10,146	3	1	31,723	10,147
California	345	113	1,613	303	1,958	416
Colorado	161,391	113,832	193,614	101,212	355,005	215,044
Idaho			44,175	10,643	44,175	10,643
Illinois	172	39	14,207	3,949	14,379	3,988
Indiana			1,890	702	1,890	702
Kansas	30,302	13,397	16,880	3,843	47,182	17,240
Kentucky			17,323	6,669	17,323	6,669
Louisiana	12,459	11,323	756	756	13,215	12,079
Michigan	89	8	6,240	1,262	6,329	1,270
Minnesota			313	104	313	104
Mississippi	2,904	1,922	1,053	447	3,957	2,369
Montana	20,149	8,541	300,339	53,655	320,488	62,196
Nevada	320	280	680	543	1,000	823
New Mexico	79,433	55,807	38,422	17,650	117,855	73,457
North Dakota	4,635	546	146,364	21,781	150,999	22,327
Ohio			202	43	202	43

	Developed(1)		Undeveloped(2)		Total	
Oklahoma	1,483,255	260,409	65,831	38,740	1,549,086	299,149
Oregon			43,869	7,671	43,869	7,671
South Dakota			204,398	107,829	204,398	107,829
Texas	149,253	58,640	39,668	36,401	188,921	95,041
Utah	90,815	79,505	233,673	111,849	324,488	191,354
Washington			26,631	10,149	26,631	10,149
West Virginia	969	115			969	115
Wyoming	231,973	150,600	413,608	263,147	645,581	413,747
Total	2,300,184	765,223	1,812,232	799,799	4,112,416	1,565,022

(1)
Developed acreage is acreage spaced or assignable to productive wells.

(2)
Undeveloped acreage is leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved reserves.

Substantially all the leases summarized in the preceding table will expire at the end of their respective primary terms unless the existing leases are renewed or production has been obtained from the acreage subject to the lease prior to that date. In that event, the lease will remain in effect until production ceases. The following table sets forth the gross and net acres subject to leases summarized in the preceding table that will expire during the periods indicated:

	Acres Expiring	
Leaseholds Expiring (in Acres)	Gross	Net
12 Months Ending December 31,		
2005	70,330	47,784
2006	90,420	64,716
2007	55,966	45,771
2008	35,139	24,154
2009 and later	25,568	22,057

Drilling Activity. The following table summarizes the number of development and exploratory wells drilled by Market Resources, including the cost-of-service wells drilled by Wexpro, during the years indicated. Questar E&P's Canadian properties were sold in the last quarter of 2002.

		Year Ended December 31,					
		Productive			Dry		
		2004	2003	2002	2004	2003	2002
Net Wells Completed							
United States	-Exploratory	4.7	3.7	0.6		0.2	1.0
	-Development	156.0	132.3	150.9	6.6	9.6	2.4
Canada	-Exploratory			0.5			
	-Development			2.3			0.4
Total	-Exploratory	4.7	3.7	1.1		0.2	1.0
	-Development	156.0	132.3	153.2	6.6	9.6	2.8
Gross Wells Completed							
United States	-Exploratory	9	10	2		2	1
	-Development	322	282	215	13	19	5
Canada	-Exploratory			1			

		Year Ended December 31,					
	-Development			9			1
Total	-Exploratory	9	10	3		2	1
	-Development	322	282	224	13	19	6

Gas Gathering and Processing

Gas Management owns 1,506 miles of gathering lines in Utah, Wyoming, Colorado and Oklahoma. In conjunction with these gathering facilities, Gas Management owns compression facilities, field-dehydration and measuring systems. Gas Management is a 50% partner in Rendezvous, which owns an additional 221 miles of gathering lines and associated field equipment.

Gas Management owns processing plants that have an aggregate capacity of 314 MMcf of unprocessed natural gas per day.

Marketing, Trading, Risk Management and Underground Gas Storage

Energy Trading, through its wholly owned subsidiary Clear Creek Storage Company, LLC, owns and operates an underground gas-storage reservoir in southwestern Wyoming.

Questar Pipeline

Questar Pipeline has a maximum capacity of 2,892 Mdth per day and firm-capacity commitments of 1,643 Mdth per day. Questar Pipeline's transmission system includes 2,497 miles of transmission lines that interconnect with other pipelines. Its core system includes two segments, often referred to as the northern system and southern system. The northern system extends from northwestern Colorado through southwestern Wyoming into northern Utah, while the southern system extends from western Colorado to Elberta, Utah. The transmission mileage includes lines at storage fields and tap lines used to serve Questar Gas, the 488 miles of the Southern Trails system in service that is owned by a subsidiary, and the 88 miles of Overthrust Pipeline owned by subsidiaries. The maximum-daily-capacity figures included above for Southern Trails and Overthrust are 88 Mdth and 899 Mdth, respectively. Questar Pipeline's system ranges in size from lines that are less than four inches in diameter to the Overthrust line that is 36 inches in diameter. Through a subsidiary, Questar Pipeline also owns 210 miles of pipeline comprising the western segment of the Southern Trails system, although this segment has not been placed in service. Questar Pipeline has major compression sites, including a complex near Rock Springs, Wyoming, that compresses gas volumes from the transmission system for delivery to other pipelines, including systems that move gas volumes east.

Questar Pipeline also owns the Clay Basin storage facility in northeastern Utah, which has a certificated capacity of 117.5 bcf, including 53.5 bcf of working gas, and several smaller storage aquifers in northeastern Utah and western Wyoming. Through a subsidiary, Questar Pipeline owns a processing plant in Price, Utah, and related gathering lines.

Questar Gas

Questar Gas distributes gas to customers in the major populated area of Utah, commonly referred to as the Wasatch Front, including the metropolitan Salt Lake area, Provo, Park City, Ogden, and Logan. It also serves customers throughout the state, including the cities of Price, Roosevelt, Vernal, Moab, Monticello, Fillmore, Cedar City and St. George. Questar Gas supplies natural gas to the southwestern Wyoming communities of Rock Springs, Green River, Evanston, Kemmerer and Diamondville and the southeastern Idaho community of Preston. To supply these communities Questar Gas owns and operates distribution systems and has a total of 24,177 miles of street mains, service lines and interconnecting pipelines. Questar Gas has a major operations center in Salt Lake City, Utah, and has operations centers, field offices and service-center facilities through other parts of its service area.

Other

Questar leases a 255,000-square-foot facility in downtown Salt Lake City, Utah, that serves as its corporate headquarters.

ITEM 3. LEGAL PROCEEDINGS.

Questar is involved in a variety of pending legal disputes. Management believes that the outcome of these cases will not have a material adverse effect on financial position, operating results or liquidity. Questar Gas's regulatory proceedings involving coverage for certain processing costs are described in Item 7. Questar Pipeline's regulatory proceedings involving fuel-gas reimbursement are discussed in Item 7. Other significant cases are discussed below.

Grynberg. Questar affiliates are involved in three separate lawsuits filed by Jack Grynberg, an independent producer. The first case, *United States ex rel. Grynberg v. Questar Corp.,* Civil No. 99-MD-1604, consolidated as *In re Natural Gas Royalties Qui Tam Litigation*, Consolidated Case MDL No. 1293 (D. Wyo.) involves *qui tam* claims filed by Grynberg under the federal False Claims Act and is substantially similar to the other cases filed against pipelines and their affiliates that have been consolidated for discovery and pre-trial discovery motions in Wyoming's federal district court. The cases involve allegations of industry-wide mismeasurement of natural gas quantities on which royalty payments are due the federal government.

The Questar defendants have finished deposing Grynberg and filed a motion contending that the court has no jurisdiction over the case because Grynberg cannot satisfy the statutory requirements for jurisdiction. In other words, the Questar defendants argue that Grynberg cannot claim to be the "original source" of the information on which the allegations are based and failed to provide any information to the government before public disclosures occurred.

A special master has been handling the consolidated cases in order to expedite administrative matters. He has scheduled a hearing on the motions to be held on March 17-18, 2005.

The second case, *Grynberg and L & R Exploration Venture v. Questar Pipeline Co.*, Civil No. 97CV0471 (D. Wyo.) was originally stayed pending the outcome of issues raised in other cases involving the parties. This case involves some of the same allegations that were heard in an earlier case between the parties, e.g., breach of contract, intentional interference with a contract, and has additional claims of antitrust violations and fraud. In June 2001 the judge entered an order granting the Company's motion filed by Questar defendants for partial summary judgment dismissing the antitrust claims from the case, but has not ruled on other motions for summary judgment dealing with ratable take and fraud.

The third case, *Grynberg v. Questar Pipeline*, No. 99090729CN (Dist. Ct. Utah), is pending in a Utah district court following a remand from the Utah Supreme Court. The district court judge recently issued an order to show cause why this case should not be dismissed for failure to prosecute and has set a hearing for March 23, 2005. This case, which was originally filed by Grynberg against Questar Pipeline and other named Questar defendants in September of 1999, involves claims that Questar entities mismeasured the heat content attributable to Grynberg's working interest in several wells in southwestern Wyoming, committed fraud, and breached fiduciary responsibilities owed him. The trial court judge granted summary judgment to the Questar defendants and dismissed Grynberg's claims. On appeal, the Utah Supreme Court substantially upheld the trial court's decision, but ruled that Grynberg was not collaterally estopped from presenting a contract-termination issue that had been previously ruled on by a Wyoming federal district court judge in another case and remanded the case to the trial court to determine whether any contractual claims remain.

Kansas Cases. Energy Trading is a named defendant in tandem cases pending in a Kansas state district court, *Price v. Gas Pipelines,* No. 99 C 30 (Dist. Ct. Kan.) and *Price v. El Paso Entities,* No. 03 C 23 (Dist. Ct. Kan.). These cases are similar to the cases filed by Grynberg, but the allegations of a conspiracy by the pipeline industry to set standards that result in the systematic undermeasurement of natural gas volumes and resulting underpayment of royalties are made on behalf of private and state lessors rather than on behalf of the federal government. The purported class involves all royalty owners of production from nonfederal and nonIndian land in Kansas, Wyoming and Colorado. Energy Trading opposes certification of the class and contends that it is not engaged in any measurement activities in Kansas. Questar affiliates engage in measurement activities, but not in Kansas.

A hearing on defendants' motion opposing class certification is scheduled to be heard on April 1, 2005.

Beaver Gas Pipeline System. On February 15, 2005, the trial court judge granted Questar E&P's motion to dismiss the lawsuit filed against it in *Kaiser-Francis Oil v. Anadarko Petroleum Corp.*, Case No. CJ-2003-66518 (Dist. Ct. Okla.). This lawsuit was filed by Questar E&P's co-defendant in a prior Oklahoma case, *Bridenstine v. Kaiser-Francis Oil Co.* The original lawsuit was a class action alleging improper royalty payments for wells connected to the Beaver Gas Pipeline System in western Oklahoma. Questar E&P and Anadarko (as the successor to another company) settled the lawsuit in December 2000 by agreeing to pay a total sum of $22.5 million, of which $16.5 million was allocated to Questar E&P. Kaiser-Francis chose not to settle and was assessed damages, including punitive damages, by a jury. Kaiser-Francis ultimately settled for $82.5 million.

Kaiser-Francis' lawsuit claimed that Questar E&P and Anadarko were obligated by express and implied indemnities to pay for a portion of the damages assessed in the jury trial and for its legal-defense costs. In dismissing the lawsuit for failure to state a claim, the district judge noted that the jury determined that Kaiser-Francis was involved in a conspiracy with other working-interest owners and was barred by the doctrine of "unclean hands" from suing Questar E&P and Anadarko.

Questar E&P has settled two additional cases involving the Beaver system that were filed by the Oklahoma State Land Commission and the Oklahoma State Tax Commission.

Consonus Cases. On February 11, 2005, Consonus settled the claims that had been filed against it in *Safeway, Inc. v. Consonus*, Civil No. 2:02-CV-1216DS (D. Utah). This suit involved claims that Safeway, a former data-center tenant, suffered irreparable damage when its computer system was rendered unfit due to an accident that occurred at the center in February 2002. Consonus did not incur any expense associated with the settlement.

Consonus, its parent (Questar InfoComm) and certain named officers and directors of Consonus have been named as defendants in the second lawsuit, *Melnyk v. Consonus, Inc.*, Case No. 2:03-CV-00528DB, pending in a federal district court. Individual defendants include Keith O. Rattie, S. E. Parks, Connie C. Holbrook, and Glenn H. Robinson, who currently serve as executive officers of Questar.

The plaintiffs are former minority shareholders who include a former officer and a former director and officer. They claim that the majority shareholders breached their fiduciary duties to minority shareholders by wasting assets and engaging in related-party transactions to the detriment of minority shareholders and the named defendants breached their fiduciary duties as officers and directors. Plaintiffs allege that they received an inadequate price for their shares in a statutory merger that occurred in mid-2003 and claim damages ranging from $2.2 million to $14.3 million for breach of fiduciary obligations.

Royalty Cases. Royalty class actions are being asserted by landowners against entities involved in the gas and oil marketing-and-production business. Questar E&P and Wexpro have been involved in several class actions and expect to be the subject of additional class-action cases involving similar claims.

Royalty payments are also audited by the Minerals Management Service, an agency within the Department of Interior, and by various states in which Questar E&P and Wexpro operate.

Environmental Matters. Questar E&P has intervened in a lawsuit that was filed by Wyoming environmental groups against the Bureau of Land Management (BLM), *Wyoming Outdoor Council v. Bennett,* Case No. 03-CV50-J (D. Wyo.) The environmental groups claim the BLM violated federal law and regulatory provisions when it approved Questar E&P's request for an exception that allowed limited drilling during the winter of 2002-03. (Questar E&P's successful efforts to extend winter drilling are described in other sections of this report.) Questar E&P contends the BLM complied with federal regulations when expanding winter drilling. Environmental groups have not appealed the latest BLM decision to grant additional access for winter drilling. A hearing on the issues was held in January 2004, but as of the date of this report the federal district court has not issued any order.

During the second quarter of 2002, the Environmental Protection Agency (EPA) issued two separate compliance orders alleging that Gas Management to comply with regulatory requirements adopted to enforce the federal Clean Air Act. Both orders involved facilities in the Uinta Basin of eastern Utah that were owned by Shenandoah Energy, Inc. (currently renamed QE&P Uinta Basin) before its purchase in mid-2001. Gas Management is currently operating the facilities and filing necessary reports in compliance with regulatory requirements. It is discussing the allegations with the EPA and expects that it may be required to pay a civil penalty in excess of $100,000 in conjunction with each order.

On January 2, 2005, the Department of Environmental Quality (DEQ) for the state of Oklahoma issued a seven-count Notice of Violation to Gas Management in conjunction with the operation of the Beaver processing plant in western Oklahoma. The DEQ alleges that Gas Management violated federal and state environmental laws and regulations concerning air emissions when operating the facility and when reporting about such operations. As requested by DEQ, Gas Management filed a compliance plan by the end of February 2005. At this point, Gas Management has not been advised of any penalties but anticipates that penalties may exceed $100,000.

Questar Pipeline received a Notice of Violation from the Colorado Department of Public Health and Environment, Air Pollution Control Division (APCD) dated February 3, 2005, in conjunction with its operation of a tank battery in Rio Blanco County, Colorado. Specifically, the Colorado agency alleged that Questar Pipeline violated applicable environmental regulations by failing to obtain the necessary permit and complying with the best available control technology. Questar Pipeline is involved in ongoing discussions with APCD. Questar Pipeline has not been advised of penalties and other assessments, but anticipates that these may exceed $100,000.

Questar defendants are listed as "responsible parties" at other sites involving hazardous wastes and have also received formal "notices of violation" or informal inquiries from state environmental agencies and the federal EPA. With the possible exceptions of an enforcement action that the EPA may bring against QEP Uinta Basin (a subsidiary of Questar E&P) for violation of air-permit requirements for operations on tribal lands in eastern Utah and the notice issued by the Oklahoma DEQ and the Colorado APCD described above, there is no pending proceeding involving formal or informal notices of violations that includes a penalty of $100,000 or more.

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

The Company did not submit any matters to a vote of stockholders during the last quarter of 2004.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Information concerning the market for the common equity of the Company and the dividends paid on such stock is located in Note 18 of the Notes to Consolidated Financial Statements under Item 8. As of March 1, 2005, Questar had 10,210 shareholders of record and estimates that it had an additional 30,000 to 35,000 beneficial holders.

Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities.

The following table sets forth the Company's purchases of common stock registered under Section 12 of the Exchange Act that occurred during the quarter ended December 31, 2004.

	Total Number of Shares Purchased*	Average Price per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet Be Purchased Under the Plans
October 1, 2004 to October 31, 2004	12,907	$ 47.67		
November 1, 2004 to November 30, 2004	5,277	49.21		
December 1, 2004 to December 31, 2004	10,901	48.44		
Total	29,085	$ 48.24		

* The numbers include shares purchased in conjunction with tax-payment elections under the Company's Long-term Stock Incentive Plan. They exclude any fractional shares purchased from terminating participants in Questar's Dividend Reinvestment and Stock Purchase Plan, any shares of restricted stock forfeited when failing to satisfy vesting conditions and any shares delivered for consideration or attested to when exercising stock options.

ITEM 6. SELECTED FINANCIAL DATA.

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(in thousands, except per-share amounts)				
Revenues	$ 1,901,431	$ 1,463,188	$ 1,200,667	$ 1,439,350	$ 1,266,153
Operating expenses					
Cost of natural gas and other products sold	840,544	542,441	395,742	675,011	562,229
Operating and maintenance	309,090	284,266	284,317	270,355	251,477
Depreciation, depletion and amortization	216,175	192,382	184,952	151,735	142,491
Questar Gas rate-refund obligation	4,090	24,939			

	Year Ended December 31,				
Other expenses	115,945	79,330	61,461	68,142	61,989
Total operating expenses	1,485,844	1,123,358	926,472	1,165,243	1,018,186
Operating income	$ 415,587	$ 339,830	$ 274,195	$ 274,107	$ 247,967
Interest and other income	$ 6,868	$ 7,435	$ 56,667	$ 35,298	$ 39,359
Income before accounting changes	$ 229,301	$ 179,196	$ 170,893	$ 158,186	$ 149,477
Cumulative effect of accounting changes		(5,580)	(15,297)		
Net income	$ 229,301	$ 173,616	$ 155,596	$ 158,186	$ 149,477
Basic earnings per common share					
Income before accounting changes	$ 2.74	$ 2.17	$ 2.09	$ 1.95	$ 1.86
Cumulative effect of accounting changes		(0.07)	(0.19)		
Net income	$ 2.74	$ 2.10	$ 1.90	$ 1.95	$ 1.86
Diluted earnings per common share					
Income before accounting changes	$ 2.67	$ 2.13	$ 2.07	$ 1.94	$ 1.85
Cumulative effect of accounting changes		(0.07)	(0.19)		
Net income	$ 2.67	$ 2.06	$ 1.88	$ 1.94	$ 1.85
Weighted-average common shares outstanding					
Used in basic calculation	83,759	82,697	81,782	81,097	80,412
Used in diluted calculation	85,722	84,190	82,573	81,658	80,915
Dividends per share	$ 0.85	$ 0.78	$ 0.725	$ 0.705	$ 0.685
Net cash provided from operating activities	$ 581,882	$ 436,373	$ 472,348	$ 377,458	$ 255,519
Capital expenditures	442,483	325,339	362,653	984,086	315,142
Capitalization at December 31,					
Long-term debt, less current portion	$ 933,195	$ 950,189	$ 1,145,180	$ 997,423	$ 714,537
Common equity	1,439,558	1,261,265	1,138,761	1,080,781	952,632
Total capitalization	$ 2,372,753	$ 2,211,454	$ 2,283,941	$ 2,078,204	$ 1,667,169
Total assets at December 31,	$ 3,646,658	$ 3,331,631	$ 3,084,983	$ 3,269,580	$ 2,484,442
Book value per-common share	$ 17.05	$ 15.15	$ 13.88	$ 13.26	$ 11.79

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

SUMMARY

Questar reported net income of $229.3 million or $2.67 per diluted share in 2004 compared to $173.6 million, or $2.06 for 2003 and $155.6 million or $1.88 in 2002. Net income in 2003 was reduced by $5.6 million or $0.07 per share due to the cumulative effect of implementing SFAS 143, a new accounting rule governing the treatment of retirement costs of long-lived assets. Net income in 2002 was reduced by $15.3 million or $0.19 per share due to the cumulative effect of change in accounting for goodwill. Following is a comparison of net income by line of business.

	Year Ended December 31,			Change	Change
	2004	2003	2002	2004 v. 2003	2003 v. 2002
	(dollars in thousands, except per-share amounts)				
Net income (loss)					
Market Resources	$ 165,411	$ 115,990	$ 97,929	$ 49,421	$ 18,061
Questar Pipeline	27,596	30,169	32,608	(2,573)	(2,439)
Questar Gas	31,461	20,182	32,399	11,279	(12,217)
Corporate and other operations	4,833	7,275	(7,340)	(2,442)	14,615
Total	$ 229,301	$ 173,616	$ 155,596	$ 55,685	$ 18,020
Earnings per common share diluted	$ 2.67	$ 2.06	$ 1.88	$ 0.61	$ 0.18

Market Resources' net income increased 43% in 2004 compared to 2003. Primary factors for the higher income were a 12% increase in production, higher realized natural gas, oil and NGL prices, increased gas-gathering throughput and gathering and processing margins, and additions to Wexpro's investment base. Market Resources' net income grew 18% in 2003 over 2002 due to higher realized prices for natural gas, oil and NGL and increased investment in gas gathering in Wyoming. The cumulative effect of implementing SFAS 143 reduced Market Resources 2003 earnings by $5.1 million. Market Resources 2002 net income included a $26.8 million after-tax gain from asset sales.

Questar Pipeline earned $27.6 million in 2004 compared with $30.2 million in 2003. The 2004 results were lower by $3.0 million after tax as a result of an order to credit to transportation customers certain revenues from the sale of liquids recovered from gas processing. A more-detailed discussion of the FERC decision follows. Net income declined in 2003 compared with 2002 because increased operating expenses and lower capitalized costs for construction projects offset a 7% increase in transportation volumes and a 10% growth in revenues. The cumulative effect of implementing SFAS 143 reduced Questar Pipeline 2003 net income by $133,000.

Questar Gas net income increased 56% or $11.3 million in 2004 versus 2003 and decreased 38% or $12.2 million in 2003 versus 2002. The 2003 results were negatively impacted by a $15.5 million after-tax charge for refund of disputed gas-processing costs, of which $11.9 million related to periods prior to 2003. Excluding the impact of the refund, Questar Gas net income decreased $0.6 million in 2004 compared with 2003. Increased revenues from new customers were offset by higher expenses and lower usage per customer. The cumulative effect of implementing SFAS 143 reduced Questar Gas 2003 earnings by $334,000.

Net income from corporate and other operations decreased $2.4 million in 2004. In 2004 Questar reorganized Questar InfoComm, shifting most information-technology activities to the other business units. Prior to 2004 Questar InfoComm provided these services and received fees from its affiliates. Corporate and other operations net income for 2003 was $14.6 million higher than 2002. Under a new accounting method adopted in the first quarter of 2002, goodwill related to the data-hosting business was determined to be impaired and written off, resulting in a $15.3 million reduction in net income.

RESULTS OF OPERATION

Market Resources

Market Resources conducts its operations through several subsidiaries. Questar Exploration and Production Company (Questar E&P) acquires, explores for, develops and produces gas and oil. Wexpro Company (Wexpro) manages, develops and produces cost-of-service reserves for affiliated company, Questar Gas. Questar Gas Management Company (Gas Management) provides gas-gathering and processing services for affiliates and third parties. Questar Energy Trading Company (Energy Trading) markets equity and third-party gas and oil, provides risk-management services, and through its wholly owned subsidiary Clear Creek Storage Company, LLC, owns and operates an underground gas-storage reservoir. Following is a summary of Market Resources' financial results and operating information.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
OPERATING INCOME			

	Year Ended December 31,		
Revenues			
Natural gas sales	$ 375,220	$ 285,118	$ 205,928
Oil and natural-gas-liquids sales	86,336	67,020	67,572
Cost-of-service gas operations	116,747	100,997	93,177
Energy marketing	525,276	348,002	212,087
Gas gathering, processing and other	81,702	67,871	50,359
Total revenues	1,185,281	869,008	629,123
Operating expenses			
Energy purchases	518,437	342,476	202,132
Operating and maintenance	144,668	130,680	131,598
Depreciation, depletion and amortization	142,688	121,316	117,446
Exploration	9,239	4,498	6,086
Abandonment and impairment of gas, oil and other properties	15,758	4,151	11,183
Production and other taxes	73,243	53,343	28,558
Wexpro Agreement oil-income sharing	4,702	2,199	1,676
Total operating expenses	908,735	658,663	498,679
Operating income	$ 276,546	$ 210,345	$ 130,444
OPERATING STATISTICS			
Nonregulated production volumes			
Natural gas (in MMcf)	89,801	78,811	79,674
Oil and natural gas liquids (in Mbbl)	2,281	2,324	2,764
Total production (in bcfe)	103.5	92.8	96.3
Average daily production (in MMcfe)	283	254	264
Average commodity price, net to the well			
Average realized price (including hedges)			
Natural gas (per Mcf)	$ 4.18	$ 3.62	$ 2.58
Oil and natural gas liquids (per bbl)	$ 30.97	$ 23.39	$ 20.39
Average sales price (excluding hedges)			
Natural gas (per Mcf)	$ 5.11	$ 4.17	$ 2.17
Oil and natural gas liquids (per bbl)	$ 38.10	$ 28.47	$ 22.93
Wexpro net investment base at December 31, (in millions)	$ 182.8	$ 172.8	$ 164.5
Natural gas-gathering volumes (in thousands of MMBtu)			
For unaffiliated customers	128,721	114,774	112,205
For Questar Gas	38,997	41,568	40,685
For other affiliated customers	56,958	46,150	38,136
Total gathering	224,676	202,492	191,026
Gathering revenue (per MMBtu)	$ 0.22	$ 0.20	$ 0.16
Natural gas and oil-marketing volumes (in Mdthe)	94,783	80,196	83,816

Market Resources Consolidated Results

Market Resources grew 2004 net income to $165.4 million versus $116.0 million in 2003, a 43% increase. Operating income increased $66.2 million, or 31%, in the year-to-year comparison from $210.3 million to $276.5 million. Total revenues increased $316.3 million, or 36%, in 2004. Revenue growth was driven by increased production, higher realized natural gas, oil and NGL prices at Questar E&P, increased throughput, higher gathering fees and improved processing margins at Gas Management, and an increased investment base in Wexpro. Revenues include sales to affiliates. Expenses increased in the 2004 period due to increased abandonment expense, exploration expense, production taxes, depreciation, depletion and amortization, and lease-operating expense.

Questar E&P Results

Questar E&P 2004 net income was $108.2 million compared to $70.4 million in 2003, a 54% increase. Higher profits were driven by increased production and higher realized natural gas, oil and NGL prices. Questar E&P 2003 net income benefited from higher prices for natural gas, oil and NGL. Realized oil and natural gas-liquid prices, net to the well, increased 15% in 2003. Realized natural gas prices, net to the well, increased 40% year over year compared to 2002. A change in accounting for asset-retirement obligations reduced Questar E&P income by $4.6 million in 2003.

Questar E&P production increased 12% to 103.5 bcfe in 2004 versus 92.8 bcfe in the prior year. Production growth was driven by accelerated development drilling on the Pinedale Anticline in western Wyoming and a 17% year-over-year increase from Midcontinent properties. Natural gas remains the primary focus of Questar E&P's exploration and production strategy. On an energy-equivalent ratio, natural gas comprised approximately 87% of production for 2004. The comparisons of energy-equivalent production by region are shown in the following table.

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in bcfe)	
Rocky Mountains			
Pinedale Anticline	23.5	15.2	8.6
Uinta Basin	24.8	29.0	26.8
Rockies Legacy	18.0	16.7	20.7
Subtotal Rocky Mountains	66.3	60.9	56.1
Midcontinent			
Tulsa	19.9	13.9	14.5
Oklahoma City	17.3	18.0	18.2
Subtotal Midcontinent	37.2	31.9	32.7
Canada			7.5
Total production	103.5	92.8	96.3

At December 31, 2004, Market Resources operated 104 producing wells on the Pinedale Anticline compared to 76 at the end of 2003. Questar E&P's 2004 production from Pinedale was 23.5 bcfe compared to 15.2 bcfe in 2003. Production volumes from the Uinta Basin in eastern Utah decreased 15% in 2004 compared to 2003. Uinta Basin production decline has flattened significantly, with second-half 2004 production volumes essentially equal to first-half 2004 results. Production from Rockies legacy properties was 18.0 bcfe in 2004 compared to 16.7 bcfe in 2003, an 8% increase. Legacy properties include all of Questar E&P's Rocky Mountain producing properties except Pinedale and the Uinta Basin. Continued good performance from Questar E&P's Hartshorne coalbed-methane development project in the Arkoma Basin of eastern Oklahoma and ongoing infill-development drilling on the Elm Grove properties in northwest Louisiana drove Midcontinent results. Current-year Midcontinent production was up 5.3 bcfe, or 17%, compared to 2003.

Questar E&P benefited from higher realized prices for natural gas, oil and NGL in 2004. The weighted-average realized natural gas price for Questar E&P (including the effects of hedging) was $4.18 per Mcf in 2004 compared to $3.62 per Mcf for 2003, a 15% increase. For 2004, realized oil and NGL prices averaged $30.97 per bbl (including the effects of hedging), compared with $23.39 per bbl in 2003, a 32% increase. A comparison of average-realized prices by region, including hedges, is shown in the following table.

	Year Ended December 31,		
	2004	**2003**	**2002**
Natural gas (per Mcf)			
Rocky Mountains	$ 3.95	$ 3.27	$ 2.14
Midcontinent	4.57	4.26	3.35
Canada			2.22
Volume-weighted average	4.18	3.62	2.58
Oil and NGL (per bbl)			

	Year Ended December 31,		
Rocky Mountains	$ 30.10	$ 21.95	$ 19.72
Midcontinent	32.98	27.04	21.67
Canada			21.03
Volume-weighted average	30.97	23.39	20.39

Realized natural gas prices in Questar E&P's core Rockies areas increased significantly in 2004 compared to 2003. Approximately 63% of Questar E&P's 2004 natural gas production came from Rockies properties. Rockies basis, the regional difference between Rockies prices and the reference Henry Hub price, averaged approximately $0.90 per MMBtu for 2004 compared to $1.27 per MMBtu for 2003. The May 2003 completion of a major interstate-pipeline expansion that delivers Rockies gas to western U. S. markets alleviated the transportation bottleneck that adversely affected Rockies gas prices during much of the first half of 2003. About two-thirds of 2003 production was in the Rockies region and one-third in the Midcontinent region. Rockies gas prices increased 53% in 2003 versus 2002. In response to lower gas prices in 2002 Questar E&P shut in 3.3 bcfe of Rockies gas production. Midcontinent realized natural gas prices were 27% higher in 2003 compared with 2002.

Approximately 76% of Market Resources' nonregulated gas production in 2004 was hedged or pre-sold at an average price of $4.04 per Mcf net to the well. Net-to-the-well prices reflect adjustments for regional basis, gathering and processing costs, and gas quality. Hedging reduced gas revenues $83.9 million in 2004. Market Resources also hedged or pre-sold approximately 66% of its oil production in 2004 at an average net-to-the-well price of $30.98 per bbl. Hedging reduced oil revenues $16.3 million during 2004. Market Resources may hedge up to 100% of its forecasted production from proved developed reserves to lock in acceptable returns on invested capital and to protect cash flows and earnings from a decline in commodity prices. Market Resources has continued to take advantage of higher natural gas and oil prices to add to its hedge positions in 2005, 2006 and 2007. Natural gas and oil hedges as of December 31, 2004, are summarized in Item 7A of this report.

Questar E&P pre-income tax cost structure is summarized in the following table.

	Year Ended December 31,		
	2004	**2003**	**2002**
		(per Mcfe)	
Lease-operating expense	$ 0.50	$ 0.49	$ 0.55
Production taxes	0.46	0.34	0.18
Lifting costs	0.96	0.83	0.73
Depreciation, depletion and amortization	1.02	0.96	0.92
General and administrative expense	0.30	0.29	0.27
Allocated-interest expense	0.21	0.23	0.27
Total	$ 2.49	$ 2.31	$ 2.19

Lifting costs were $0.13 per Mcfe higher in 2004 versus 2003 due primarily to a 35% increase in production taxes resulting from higher sales prices of natural gas, oil and NGL. Most production taxes are based on a fixed percentage of commodity-sales prices. Depreciation, depletion and amortization expense increased 6% in 2004 compared to a year ago due to higher reserve-replacement costs and ongoing depletion of older, lower-cost successful-efforts pools. Increased competition for rigs and other services in core operating areas, along with sharply higher steel prices, has increased drilling and completion costs. General and administrative expenses increased $0.01 per Mcfe, or 3%, in 2004 versus 2003 due primarily to higher labor and employee-benefit costs and higher compliance costs. Allocated interest decreased about 9% on a unit-of-production basis to $0.21 per Mcfe versus $0.23 per Mcfe in 2003 due primarily to increased production volumes.

Lease-operating expenses were lower in the 2003 period after the 2002 sale of higher-cost Canadian and other properties. Higher sales prices in 2003 compared with 2002 resulted in higher production taxes. Depreciation, depletion and amortization rates increased in 2003 over 2002 due to higher costs and, in part, lower estimated reserves in Questar E&P's Uinta Basin properties.

In 2004 impairments totaling $5.7 million were recognized for Bovina field in Mississippi due to collapsed casing on one well, and the uneconomic coalbed-methane play at the Copper Ridge Unit in Wyoming. Dry-hole expense of $3.9 million was recorded for the unsuccessful exploratory zones in the Brady Field.

Pinedale Anticline Drilling Activity

During 2004 Market Resources drilled and completed 28 wells, had four additional wells drilled to intermediate casing point and suspended until May 2005, and had three wells waiting on completion at year-end. Two of the wells waiting on completion were completed and turned to sales in January 2005. In addition, two rigs were actively drilling on the winter pad on December 31, 2004. In mid-July 2004, Market Resources commenced drilling a well to test the deep potential of its Pinedale acreage. The 19,500-foot Stewart Point 15-29 well, designed to test the potential of the Rock Springs and Blair formations beneath the Lance Pool pay zones at Pinedale, was delayed over two months due to sage grouse activity. The pace of drilling on the well was hampered by chronic mechanical problems with the contracted drilling rig and inexperienced rig crews. In November 2004, drilling operations were suspended at intermediate casing point at a depth of 14,200 feet and the rig was released. A different rig will be used to finish drilling the well to total depth when operations resume in May 2005.

Pinedale Anticline Year-Round Drilling Proposal

On April 15, 2004, Market Resources submitted a proposal to the BLM seeking a long-term exception to the winter-drilling restrictions on its Pinedale acreage from November 15 through May 1. On November 9, 2004, a BLM Decision gave Market Resources approval to phase-in over the next year the company's proposed year-round drilling program. The BLM decision allows Market Resources to operate two drilling rigs on one pad during the winter of 2004-2005. After a proposed water- and condensate-gathering line is completed in 2005, Market Resources will be allowed to operate six rigs from three active pads beginning in the winter of 2005-2006 through the winter of 2013-2014.

Market Resources believes that year-round drilling from pads is the most efficient and environmentally responsible approach for developing its Pinedale acreage. Market Resources' year-round drilling program will shorten the anticipated development drilling period from 18 years to about 9 years. Market Resources can drill up to 16 directional wells per single surface pad. With year-round drilling, surface disturbance will be reduced initially by about two-thirds from almost 1,500 acres currently allowed to around 500 acres. Surface disturbance would be further reduced to less than 250 acres with post-drilling reclamation.

Other benefits of Market Resources' year-round drilling program include a substantial reduction in emissions, noise, dust and traffic compared to the current situation in which activities are compressed into the summer months. Year-round drilling also creates year-round jobs and thus a more-stable, better-trained, more-productive and safer workforce in the drilling and completion-service industries.

Market Resources has committed to build pipelines to transport condensate and water production off the portion of the Pinedale Anticline where Market Resources' acreage is located. The pipelines will eliminate the need for storage tanks at each location and up to 25,500 tanker-truck trips per year at peak production. Other key components of the BLM decision are funding for continued monitoring of mule deer and other critical wildlife, monitoring air quality, and habitat enhancement on contiguous undeveloped areas of Market Resources' Pinedale leasehold.

Pinedale Anticline 20-Acre Spacing Approved

During the third quarter of 2004, the Wyoming Oil and Gas Conservation Commission issued a formal order approving 20-acre-density drilling of Lance Pool (Lance and Mesaverde Formation) wells on all of Market Resources Pinedale Anticline acreage held at the end of 2003 (approximately 14,800 acres). With 20-acre spacing Market Resources has up to 470 total well locations on its Pinedale leasehold (including several recently acquired tracts that have not yet been approved for 20-acre spacing) with approximately 359 locations remaining to be drilled at the end of 2004. Market Resources has over 17,951 gross acres under lease at Pinedale. Questar E&P and Wexpro have a combined 67% average working interest in the 470 total development locations covering approximately 9,400 productive acres in the Lance Pool (combined Lance and Mesaverde formations) at Pinedale. Of the 470 gross Lance Pool development locations on Market Resources' leasehold, Questar E&P has about 263 net locations and Wexpro has about 54.

Market Resources estimates that each 20-acre-spaced well drilled and completed in the Lance and Mesaverde Formations will recover between 3.8 and 8.8 bcfe of gross-incremental reserves. Questar E&P's average working interest in horizons beneath the productive limits of the Lance Pool is approximately 75%. Wexpro has no working interest in deeper horizons.

New Pinedale Leases

During the third quarter of 2004, Questar E&P acquired additional federal leases on 2,018 acres adjacent to the southwest side of the current 14,800-acre leasehold. Subject to approval of 20-acre spacing, this newly acquired Pinedale acreage may add up to 32 drilling locations. Questar E&P has a 100% working interest in these new leases. Several groups have appealed the issuance of these leases.

Wexpro

Wexpro net income increased 8% to $35.3 million in 2004 compared to $32.6 million in 2003. Wexpro manages, develops and produces gas reserves for affiliated company Questar Gas. Wexpro activities are governed by a long-standing agreement (Wexpro Agreement) with the states of Utah and Wyoming. Pursuant to the Wexpro Agreement, Wexpro recovers its costs and receives an unlevered after-tax return of approximately 19% on its net investment in commercial wells and related facilities known as the investment base adjusted for working capital, deferred taxes, and depreciation. Wexpro's net investment base increased to $182.8 million at December 31, 2004, up $10 million over 2003. Wexpro's net income also benefited from higher oil and NGL prices in 2004.

Wexpro earned $32.6 million in 2003 compared to $30.8 million in 2002 due to increased investment in gas-development wells, higher realized prices for oil, capitalized interest associated with construction, and lower debt expense. Wexpro's 2003 results included a $0.5 million after-tax charge for the cumulative effect of an accounting change for asset-retirement obligations.

Gas Gathering and Processing

Net income from gas-gathering and processing services increased 58% to $21 million in 2004 versus $13.3 million in 2003. Gathering margins increased by $7 million due to an 11% increase in volumes and a 2.3-cent-per-MMBtu increase in gathering rates. Pinedale production and new projects serving third parties in the Uinta Basin are driving the expanded service. Gas Management gas-processing margins (revenue from the sale of natural gas liquids less natural gas purchases and operating expenses) improved by 7.6 cents per gallon due to higher NGL sales prices. To reduce processing-margin volatility, Gas Management began hedging NGL prices in 2004 using forward-sales contracts. Hedging reduced NGL revenues by $0.5 million in 2004.

Net income from gas-gathering and processing operations increased 46% to $13.3 million in 2003 compared to 2002. Gathering volumes increased 11.5 MMBtu to 202.5 MMBtu in 2003 as the result of increased investment in gathering facilities in the Pinedale area.

Pre-tax earnings from Gas Management's 50% interest in Rendezvous increased to $5 million in 2004 from $4.7 million for 2003 and $2.2 million in 2002. Rendezvous provides gas-gathering services for the Pinedale and Jonah producing areas.

Gas and Oil Marketing and Trading, Risk Management and Gas Storage

Net income from Energy Trading was $0.9 million in 2004 compared to a loss of $0.4 million in the year-earlier period. Gross margins for gas and oil marketing (gross revenues less the costs to purchase gas and oil, commitments to gas-transportation contracts on interstate pipelines, and gas-storage costs), increased to $6.8 million for 2004 versus $5.4 million for 2003. Current-year results were positively impacted by higher unit margins and increased sales volumes. Gross margins declined in 2003 compared with 2002 due primarily to losses from long-term transportation contracts that were above market rates for much of 2003.

Energy Trading is the sole member in Clear Creek Storage, LLC, which owns and operates the Clear Creek natural gas-storage facility in southwestern Wyoming. Clear Creek has working-gas-storage capacity of approximately 3 bcf and is connected to four interstate pipelines Kern River, Northwest, Overthrust and Questar Pipeline.

Questar Pipeline

Questar Pipeline provides FERC-regulated interstate natural gas transmission and storage, and nonjurisdictional processing and gathering services. Following is a summary of financial results and operating information.

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
OPERATING INCOME			
Revenues			
Transportation	$ 105,464	$ 103,579	$ 93,007
Storage	37,690	37,616	37,673
Carbon-dioxide processing	7,348	7,281	6,241
Liquid revenues and other	5,977	8,362	5,954
Total revenues	156,479	156,838	142,875
Operating expenses			
Operating and maintenance	55,654	53,249	49,593
Depreciation and amortization	28,235	26,141	22,149
Other taxes	6,557	6,352	4,948

	Year Ended December 31,		
Total operating expenses	90,446	85,742	76,690
Operating income	$ 66,033	$ 71,096	$ 66,185
OPERATING STATISTICS			
Natural gas-transportation volumes (in Mdth)			
For unaffiliated customers	220,514	251,665	245,119
For Questar Gas	116,454	105,720	111,692
For other affiliated customers	18,803	26,224	6,044
Total transportation	355,771	383,609	362,855
Transportation revenue (per dth)	$ 0.30	$ 0.27	$ 0.26
Firm daily-transportation demand at December 31, (Mdth)	1,643	1,655	1,543

Questar Pipeline's net income was $27.6 million in 2004 compared with $30.2 million in 2003 and $32.6 million in 2002. The 2004 net income was reduced by $3 million because of an order from the FERC crediting liquid revenues to customers as discussed below.

Revenues

Questar Pipeline's revenues were flat in 2004 versus 2003 after increasing by 10% in 2003 versus 2002. Revenues include sales to affiliates. Following is a summary of major changes in Questar Pipeline's revenues.

	Change in Revenues	
	2003 to 2004	2002 to 2003
	(in thousands)	
Transportation revenues		
New transportation contracts	$ 4,300	$ 4,900
Expiration of transportation contracts	(1,300)	(2,100)
Eastern segment of Southern Trails in service June 2002		8,100
Changes in interruptible transportation and other	(1,100)	(300)
Carbon-dioxide processing		1,000
Liquid revenues and other		
Change in liquid revenues before credit	2,500	1,800
Credit of liquid revenues	(4,700)	
Other changes	(100)	600
Increase (decrease)	$ (400)	$ 14,000

Questar Pipeline added new transportation capacity and contracts in 2003 for deliveries to Kern River Pipeline at Roberson Creek near the regional market hub at Opal, Wyoming, and for increased deliveries to Questar Gas. Questar Pipeline did not increase transportation capacity during 2004.

Questar Pipeline's existing transportation system is nearly fully subscribed. As of December 31, 2004, Questar Pipeline had firm-transportation contracts of 1,643 Mdth per day compared with 1,655 Mdth per day as of December 31, 2003, and 1,543 Mdth per day as of December 31, 2002. The amounts include 80 Mdth per-day capacity on the eastern segment of Southern Trails, which was placed in service in June 2002. Questar Pipeline's firm-transportation contracts had a weighted-average remaining life of 9.3 years as of December 31, 2004.

Questar Gas is Questar Pipeline's largest transportation customer with contracts for 951 Mdth per day, including 50 Mdth per day for winter-peaking service. The majority of Questar Gas's transportation contracts extend to 2017.

Questar Pipeline's primary storage facility is Clay Basin in eastern Utah. This facility was 100% contracted as of December 31, 2004. One contract expires in the first quarter of 2005 but is expected to be resold. In addition to Clay Basin, Questar Pipeline also owns and operates three smaller aquifer gas-storage facilities. Questar Pipeline's firm-storage contracts had a weighted-average remaining life of 7.4 years as of December 31, 2004.

Questar Gas has contracted for 26% of firm-storage capacity at Clay Basin for terms extending from four to 15 years, and 100% of the firm-storage capacity at the aquifer facilities for terms extending for 15 years.

During the fourth quarter of 2004, the FERC issued an order to Questar Pipeline in a case involving the annual fuel-gas-reimbursement percentage (FGRP). As a result Questar Pipeline recorded a revenue reduction in 2004 of $4.7 million, which included $2.3 million for prior years, as a potential credit to customers. The FERC previously granted Questar Pipeline's request to increase the FGRP effective January 1, 2004. In its order, the FERC approved the FGRP but also ruled that Questar Pipeline is required to credit to transmission customers proceeds from the sale of natural gas liquids recovered from its hydrocarbon dew-point facilities at the Kastler plant in northeastern Utah. Questar Pipeline has filed a request for rehearing with the FERC. Questar Pipeline believes that any credit to customers should be reduced by the plant's cost of service. Until the issue is resolved, Questar Pipeline will continue to accrue a potential liability equal to any liquid revenues from the dew-point plant.

Questar Pipeline charges FERC-approved transportation and storage rates that are based on straight fixed-variable rate design. Under this rate design all fixed costs of providing service, including depreciation and return on investment, are recovered through a fixed-reservation charge per unit of contracted-transportation capacity, or a demand charge. About 95% of Questar Pipeline costs are fixed and recovered through these demand charges. Questar Pipeline's earnings are driven primarily by demand revenues from firm shippers. Operating costs that vary based on throughput are recovered through volumetric charges. Since demand charges are based on contract levels and volumetric charges are about 5% of the total customer charge, period-to-period changes in firm-transportation volumes do not have a significant impact on earnings.

Questar Transportation Services, a subsidiary of Questar Pipeline, owns nonjurisdictional gathering lines and a processing plant near Price, Utah. Transportation Services built the plant in 1999 for Questar Gas to remove carbon dioxide from gas prior to delivery to Questar Pipeline. Questar Gas has contracted for 100% of the plant's firm capacity and pays the cost of service for operating the plant.

Expenses

Operating and maintenance expenses increased 5% in 2004 compared with 2003 and 7% in 2003 compared with 2002. The increases were primarily due to higher employee-benefit costs, and higher costs associated with maintenance and continued marketing of the western segment of the Southern Trails Pipeline. Operating and maintenance expenses per dth transported were $0.156 in 2004 compared with $0.139 in 2003 and $0.137 in 2002.

Depreciation expense increased 8% in 2004 over 2003 and 18% in 2003 over 2002, reflecting increased pipeline investment.

Clay Basin Storage

Questar Pipeline continues to investigate a potential discrepancy of up to 9 bcf between the book volumes of cushion gas at Clay Basin and cushion-gas volumes implied by pressure-survey data obtained in recent field tests. The current book volume of the cushion gas is 61.5 bcf with a value of $99.7 million. Questar Pipeline has not determined if any gas is missing from the reservoir. Analysis to date has not revealed any leaks or gas migration out of the reservoir. Additional reservoir tests and analysis, including reservoir modeling, are under way to identify the cause of the potential discrepancy and may continue for several years. The gas may still be in the reservoir but not detectible with short-duration pressure surveys. Pressure-survey tests were conducted during October 2004 to evaluate the reservoir when it was nearly full. The preliminary results of these tests show that the discrepancy may not be significant. This potential discrepancy has not affected Questar Pipeline's ability to meet its obligations to storage customers.

If Questar Pipeline determines that the discrepancy is due to changes in the physical conditions in the storage reservoir, the financial impact may include some additional investment in cushion gas to meet service obligations. If the discrepancy is due to lost-and-unaccounted-for-gas in the measurement process, Questar Pipeline would expense the cost of replacement gas and could file with the FERC to recover costs from customers.

New Long-Term Contracts

During first-quarter 2004 Questar Pipeline signed long-term contracts to support a $54 million expansion of its central Utah transmission system. The expansion will add 102 Mdth per day of capacity from the Piceance and Uinta basins to the Kern River pipeline, a power-generation facility, and Questar Gas's distribution system. Questar Pipeline will start construction in the summer of 2005 for a late-2005 in-service date. On January 21, 2005, the FERC approved the expansion.

Questar Pipeline has signed a long-term contract supporting a $14 million extension from the west end of its Mainline 104 near Goshen, Utah, to a new power plant near Mona, Utah. Construction was completed in December 2004 on this 190-Mdth-per-day line and service should begin during the first quarter of 2005.

Southern Trails

The eastern segment of the Southern Trails line, which runs between the San Juan basin and the California border, was placed into service in mid-2002. Capacity on this segment is fully contracted, although these contracts expire in mid-2008. At this time, market-transportation rates between the receipt and delivery points are less than current contract rates. Earnings on the eastern segment may decrease when these contracts expire.

The western segment of the Southern Trails line, which runs from the California-Arizona border to Long Beach, California, is currently not in service. Questar Pipeline's investment is approximately $51 million. Additional investment would be required to complete the conversion of the pipeline from a liquid pipeline to a natural gas pipeline and make connections to customers. The Los Angeles Department of Water and Power (LADWP) budgeted funds to acquire a gas pipeline to serve a power-generation facility and issued a request for proposal on October 21, 2004. Questar Pipeline filed a response to the request in November 2004. On February 28, 2005, LADWP notified Questar Pipeline of its intent to pursue the proposal, although it is uncertain whether negotiations will be successful.

Regulation

FERC Order No. 2004, which defines standards of conduct for transmission providers, became effective on September 22, 2004. These standards of conduct are designed to ensure that employees engaged in transmission-system operations function independently from employees of marketing and energy affiliates. In addition, a transmission provider must treat all transmission customers on a non-discriminatory basis and must not operate its transmission system to preferentially benefit its marketing or energy affiliates. Questar Pipeline has determined that all Market Resources subsidiaries except Gas Management are marketing or energy affiliates. Questar Gas is not an energy or marketing affiliate. Questar Pipeline and other Questar companies have adopted new procedures to comply with this order.

Questar Pipeline is required to comply with the Pipeline Safety Improvement Act of 2002. This act and the rules issued by the Department of Transportation (DOT) require interstate pipelines and local distribution companies to implement a 10-year program of risk analysis, pipeline assessment and remedial repair for transmission pipelines located in high-consequence areas such as densely populated locations. Questar Pipeline's plan for complying with the act was filed with the DOT during 2004. Questar Pipeline estimates that its annual cost to comply with the act will be approximately $1 million, not including costs of pipeline replacement, if necessary.

Questar Pipeline made an annual FGRP filing with the FERC on November 30, 2004, requesting an increase in the FGRP to 2.6%. On December 30, 2004, the FERC approved the request on an interim basis subject to refund and final resolution of the 2004 FGRP proceeding. Several shippers have filed comments with the FERC protesting the FGRP level.

Questar Gas

Questar Gas distributes natural gas in Utah, southwestern Wyoming and southeastern Idaho. Following is a summary of financial results and operating information.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
OPERATING INCOME			
Revenues			
Residential and commercial sales	$ 680,658	$ 552,773	$ 521,716
Industrial sales	49,094	45,279	44,488
Transportation for industrial customers	6,355	7,108	7,222
Other	28,086	15,835	22,085
Total revenues	764,193	620,995	595,511
Cost of natural gas sold	536,128	394,523	370,294

	Year Ended December 31,		
Margin	228,065	226,472	225,217
Operating expenses			
Operating and maintenance	104,786	100,279	105,544
Rate-refund obligation	4,090	24,939	
Depreciation and amortization	41,956	40,126	39,771
Other taxes	9,767	9,743	9,548
Total operating expenses	160,599	175,087	154,863
Operating income	$ 67,466	$ 51,385	$ 70,354
OPERATING STATISTICS			
Natural gas volumes (in Mdth)			
Residential and commercial sales	92,975	84,393	90,796
Industrial sales	8,823	9,613	10,729
Transportation for industrial customers	34,278	38,341	46,459
Total industrial	43,101	47,954	57,188
Total deliveries	136,076	132,347	147,984
Natural gas revenue (per dth)			
Residential and commercial	$ 7.32	$ 6.55	$ 5.75
Industrial sales	5.56	4.71	4.15
Transportation for industrial customers	0.19	0.19	0.16
System natural gas cost (per dth)	$ 5.20	$ 4.13	$ 3.14
Heating degree days colder (warmer) than normal	3%	(7)%	8%
Temperature-adjusted usage per customer (in dth)	114.9	118.9	117.4
Customers at December 31,	794,117	770,494	750,128

Questar Gas earned $31.5 million in 2004 compared to $20.2 million in 2003 and $32.4 million in 2002. Questar Gas 2003 earnings included after-tax charges of $15.5 million related to a long-standing dispute in Utah over the recovery of gas-processing and heat-content-management costs. Of the charges, $3.6 million related to 2003 and the remainder to prior years. Questar Gas 2004 net income was reduced by $4.3 million for these unrecovered costs.

Margin Analysis

Questar Gas's margin increased 1% in 2004 over 2003 and 1% in 2003 over 2002. Revenues include sales to affiliates. Following is a summary of major changes in Questar Gas's margin.

	Change in margin	
	2003 to 2004	2002 to 2003
	(in thousands)	
General rate case December 2002		$ 11,200
New customers	$ 5,100	1,800
Change in usage per customer	(6,300)	4,300
Estimated impact of warmer-than-normal weather		(1,900)
2002 customer contributions in excess of general rate-case amount		(5,600)
2002 recovery of gas-processing costs		(3,800)
Recovery of gas-cost portion of bad-debt costs	1,400	(1,500)
Change in gas costs recovered through general rate case		(2,100)

	Change in margin	
Other	1,400	(1,100)
Total	$ 1,600	$ 1,300

Effective December 30, 2002, the PSCU approved an $11.2 million general-rate increase and an 11.2% allowed return on equity. The PSCU based the increase on November 2002 rate base, operating costs and usage per customer.

At December 31, 2004, Questar Gas was serving 794,117 customers. Customer growth remained above industry averages at 3.1% over the prior year. Housing construction in Utah remained strong. Usage per customer, adjusted for normal temperatures, declined 3.4% in 2004 compared with 2003 after increasing 1.3% in 2003 compared with 2002. Usage per customer has been decreasing due to more-efficient appliances and construction and customer response to higher prices.

Weather, as measured in heating-degree days for the Questar Gas service area, was 3% colder than normal in 2004, 7% warmer than normal in 2003 and 8% colder than normal in 2002. A weather-normalization adjustment on customer bills generally offsets financial impacts of moderate temperature variations. However, significantly warmer-than-normal weather during September and October 2003 resulted in a margin reduction of $1.9 million.

Questar Gas's 2002 results included $3.8 million in recovery of previously denied gas-processing costs. These costs are part of a continuing dispute as discussed below.

The 2002 results also included revenues of $5.6 million due to up-front customer contributions in-aid of construction for new connections. Accounting for customer contributions changed beginning in 2003 as a result of the 2002 Utah general rate case. Customer contributions are now recorded as a reduction of investment instead of revenues.

Industrial deliveries declined 10% in 2004 versus 2003 and 16% in 2003 versus 2002 due primarily to lower usage of gas for power generation.

Operating Expense

Cost of natural gas sold increased 36% in the 2004 versus 2003 and 7% in 2003 versus the year earlier period. The 2004 change was due to increased volumes and higher natural gas-purchase costs. The 2003 increase over 2002 was due to higher cost of purchased natural gas. Questar Gas accounts for purchased-gas costs in accordance with procedures authorized by the PSCU and the PSCW. Purchased-gas costs that are different from those provided for in present rates are accumulated and recovered or credited through future rate changes. As of December 31, 2004, Questar Gas had a $35.9 million balance in the purchased-gas-adjustment account representing gas costs incurred but not yet recovered from customers. Effective October 1, 2004, the PSCU and PSCW authorized Questar Gas to increase customer rates by about 10% to reflect higher projected gas costs and to recover the balance in the purchased-gas-adjustment account.

Operating and maintenance expenses increased 4% in 2004 compared with 2003, after decreasing 5% in 2003 compared with 2002. Higher employee-benefit costs, contracted services and bad-debt costs in 2004 were partially offset by lower information-technology costs. The 2003 decrease was due to lower information-technology and bad-debt expenses.

Depreciation expense increased 5% in 2004 compared with 2003 and 1% in 2003 compared with 2002. Plant additions, including a customer-information system that was placed in service in July 2004, have increased depreciation expense.

In July 2004, Questar Gas implemented a new customer-information system. The new system provides critical customer-service functions including billing, collections, cash receipts, customer sign-up, service requests and dispatch. The implementation took approximately 18 months and cost approximately $20 million.

Rate-Refund Obligation

On August 1, 2003, the Utah Supreme Court issued an order reversing an August 2000 decision made by the PSCU concerning certain natural gas-processing costs incurred by Questar Gas. The court ruled that the PSCU did not comply with its statutory responsibilities and regulatory procedures when approving a stipulation in Questar Gas's 1999 general rate case. The stipulation permitted Questar Gas to collect $5.0 million per year, a portion of the processing costs, through May 2004. The Committee of Consumer Services, a Utah state agency, appealed the PSCU's decision, arguing that the PSCU had failed to explicitly address whether the costs were prudent.

As a result of the court's order, Questar Gas recorded a liability for a potential refund to gas-distribution customers. A total liability of $29.0 million, including $4.1 million recorded in the first nine months of 2004, includes revenue received for processing costs and interest from June 1999 through September 2004.

On August 30, 2004, the PSCU ruled that Questar Gas failed in 1999 to prove that its decision to contract for gas processing with an affiliate was prudent. The PSCU rejected the stipulation, denied the request for rate recovery and ordered the refund of gas-processing costs previously collected in rates. Because Questar Gas had previously accrued a liability for the refund, the order did not have a material impact on 2004 earnings. Questar Gas reduced its rates on September 1, 2004, to eliminate the collection of gas-processing costs and on October 1 began refunding previously collected costs, plus interest, over a 12-month period. As of December 31, 2004, Questar Gas had a liability of $20.6 million of remaining refunds to customers.

In response to a Questar Gas petition, the PSCU clarified that its order did not preclude recovery of ongoing and certain past-processing costs. Ongoing processing costs are approximately $6 million per year. Questar Gas has requested ongoing rate coverage for gas-processing costs in its pass-through filings, but is not currently collecting these costs in rates. The PSCU has conducted several technical conferences to determine what should be done to manage the heat content of the gas supply. On January 31, 2005, Questar Gas filed a rate request with the PSCU to recover $5.7 million per year of gas-processing costs through its gas-balance account.

Regulation

Questar Gas is subject to the requirements of the Pipeline Safety Improvement Act. Questar Gas estimates that it will cost $4 to $5 million per year to comply with the act, not including costs of pipeline replacement if necessary. The PSCU has allowed Questar Gas to record incremental operating costs to comply with this act as a regulatory asset until the next rate case or three years, whichever is sooner.

Questar Gas is not an energy or marketing affiliate of Questar Pipeline under FERC Order No. 2004. Questar Gas has adopted new procedures to comply with the order.

Corporate and Other Operations

Corporate and other operations include other services and activities. Revenues include sales to affiliates.

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in thousands)	
OPERATING INCOME			
Revenues	$ 35,645	$ 48,113	$ 50,225
Operating expenses			
Cost of products sold	5,892	4,651	6,367
Operating and maintenance	19,534	30,416	29,922
Depreciation and amortization	3,296	4,799	5,586
Other taxes	1,381	1,243	1,138
Total operating expenses	30,103	41,109	43,013
Operating income	$ 5,542	$ 7,004	$ 7,212

Revenues decreased 26%, operating and maintenance decreased 36% and depreciation decreased 31% in 2004 compared with 2003 due to the reorganization of information-technology-related businesses. Questar reorganized its information-technology services in June 2004, resulting in a small staff reduction and $0.6 million of severance costs. The remaining information-technology assets and employees were transferred to affiliates. Revenues decreased 4% in 2003 compared with 2002 with the company's exit from the equipment-resale business.

Costs of products sold increased 27% in 2004 compared with 2003 resulting from a growth in providing data storage and contracted-field services. Operating and maintenance expenses increased 2% in 2003 compared with 2002 primarily in response to higher rent charges.

Consolidated Operating Results After Operating Income

Interest and Other Income

Details of interest and other income are below.

	Year ended December 31,		
	2004	2003	2002
	(in thousands)		
Interest income and other earnings	$ 2,189	$ 4,021	$ 6,067
Net gain (loss) from asset sales	336	(525)	43,683
Allowance for other funds used duringconstruction (capitalized finance costs)	273	1,125	3,516
Return earned on working-gas inventory and purchased-gas-adjustment account	4,070	2,814	3,401
Total	$ 6,868	$ 7,435	$ 56,667

Earnings of Unconsolidated Affiliates

Rendezvous Gas Services income increased in 2004 due to higher gas throughput on its gathering system. Gas Management is a 50% member in Rendezvous, which provides gas-gathering services for the Pinedale-Jonah producing area of western Wyoming. Questar Pipeline's share of earnings from TransColorado, Overthrust and Gas Management's share of Blacks Fork earnings are included in 2002. Questar Pipeline sold its TransColorado Pipeline interest in 2002. Also, Questar Pipeline became sole owner of Overthrust Pipeline and Gas Management became the sole owner of the Blacks Fork processing plant in the fourth quarter of 2002.

Debt Expense

Lower debt balances and long-term interest rates resulted in lower debt expense in 2004 compared with 2003. In 2004 and 2003 Questar Gas replaced higher-cost fixed-rate debt with lower-cost fixed- and floating-rate debt. Market Resources reduced its revolving long-term debt by $55.0 million in 2004 and $145.0 million in 2003.

Income Taxes

The effective combined federal, state and foreign income tax rate was 36.1% in 2004, 36.4% in 2003 and 34.8% in 2002. The Section 29 income tax credit associated with production of nonconventional fuels expired December 31, 2002. The nonconventional-fuel credits amounted to $6.6 million in 2002.

Cumulative Effect of Changes in Accounting Methods

On January 1, 2003, the Company adopted a new accounting rule, SFAS 143, "Accounting for Asset Retirement Obligations" and recorded a cumulative effect that reduced net income by $5.6 million, or $0.07 per diluted common share. A year earlier, the Company adopted SFAS 142, "Goodwill and Other Intangible Assets," that resulted in impairment of acquired goodwill. A subsidiary of Questar InfoComm wrote off $17.3 million of goodwill, of which $15.3 million, or $0.19 per diluted common share, was Questar InfoComm's share, and reported as a cumulative effect of a change in accounting for goodwill. The remaining $2.0 million was attributed to minority shareholders.

LIQUIDITY AND CAPITAL RESOURCES

Operating Activities

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Net income	$ 229,301	$ 173,616	$ 155,596

	Year Ended December 31,		
Noncash adjustments to net income	354,117	296,725	261,434
Changes in operating assets and liabilities	(1,536)	(33,968)	55,318
Net cash provided from operating activities	$ 581,882	$ 436,373	$ 472,348

Net cash provided from operating activities increased 33% in 2004 compared with 2003 due primarily to increased income and noncash adjustments to income.

Investing Activities

Capital spending amounted to $442.5 million in 2004. The details of capital expenditures in 2004 and 2003, and a forecast for 2005 are as below. Corporate and other operations includes $25.0 million of yet-to-be-defined capital expenditures in 2005.

	Year Ended December 31,		
	2005 Forecast	2004	2003
		(in thousands)	
Market Resources			
Drilling and other exploration	$ 17,400	$ 29,229	$ 11,055
Development drilling	220,800	222,455	146,608
Wexpro development drilling	47,800	39,184	33,028
Reserve acquisitions		1,131	2,492
Production	13,400	13,640	9,687
Gathering and processing	71,500	26,979	31,448
Storage	300	1,171	333
General	4,300	12,040	3,480
	375,500	345,829	238,131
Questar Pipeline			
Transmission system	83,400	27,828	17,883
Storage	14,900	1,971	1,286
Southern Trails Pipeline	800	52	121
Gathering and processing	100	438	500
General	2,700	1,826	2,564
	101,900	32,115	22,354
Questar Gas			
Distribution system and customer additions	60,900	53,092	47,638
General	21,800	24,131	23,885
	82,700	77,223	71,523
Corporate and Other Operations	27,000	2,574	3,408
	587,100	457,741	335,416
Capital expenditure accruals		(15,258)	(10,077)
Total capital expenditures	$ 587,100	$ 442,483	$ 325,339

Market Resources

In 2004 Market Resources increased drilling activity at Pinedale and in the Midcontinent region. During 2004 Market Resources participated in 413 wells (167.3 net), resulting in 160.7 net successful gas and oil wells and 6.6 net dry or abandoned wells. The net drilling-success rate was 96% in 2004. There were 67 gross wells in progress at year end. Market Resources also increased investment in its midstream gathering and processing-services business to expand capacity in both western Wyoming and eastern Utah in response to growing equity and third-party production volumes.

Questar Pipeline

During 2004, Questar Pipeline completed a new pipeline extension to a power plant in Mona, Utah and began an expansion of its southern system.

Questar Gas

During 2004, Questar Gas added 854 miles of main, feeder and service lines to provide service to 23,623 new customers and completed the installation of a new customer-information system.

Financing Activities

Net cash flow provided from operating activities exceeded the sum of net capital expenditures and dividends by $75.2 million in 2004 and $57.5 million in 2003. The Company used surplus cash flow generated from operations to repay debt. Market Resources repaid $55 million of revolving long-term debt using cash flow from operations. Questar Gas retired $17 million of long-term debt. Market Resources paid down its revolving debt by $145 million, and Questar Gas refinanced $105 million of long-term debt in 2003.

Short-term borrowings amounted to $68 million at December 31, 2004, compared with $105.5 million a year earlier. The weighted-average interest rate on short-term debt balances at December 31 was 2.45% in 2004 and 1.11% in 2003. Questar commercial-paper borrowings are backed by short-term line-of-credit arrangements. Lines-of-credit capacity was $210 million at December 31, 2004.

Questar consolidated capital structure consisted of 41% combined short- and long-term debt and 59% common shareholders' equity at December 31, 2004. A year earlier debt represented 47% and shareholders' equity 53% of capitalization. Ratings of senior-unsecured debt as of December 31, 2004, were as follows.

	Moody's	Standard & Poor's
Market Resources	Baa3	BBB+
Questar Pipeline	A2	A+
Questar Gas	A2	A+
Questar short-term debt	P2	A1

Moody's ratings are designated as stable while the Standard & Poor's ratings carry a negative outlook qualifier.

The Company typically has negative net working capital at December 31 because of short-term borrowing. The borrowing is seasonal and generally peaks at the end of the year because of the lag in receivables related to cold-weather gas purchases for distribution customers.

Contractual Cash Obligations and Other Commitments

In the course of ordinary business activities, Questar enters into a variety of contractual cash obligations and other commitments. The following table summarizes the significant contractual cash obligations as of December 31, 2004.

	Payments Due by Year				
	Total	2005	2006-2007	2008-2009	After 2009
	(in millions)				
Long-term debt	$ 933.5		$ 210.0	$ 101.3	$ 622.2
Gas-purchase contracts	183.3	$ 141.7	41.6		
Transportation contracts	113.1	10.1	19.8	19.4	63.8

	Payments Due by Year				
Operating leases	44.6	5.1	9.5	8.1	21.9
Total	$ 1,274.5	$ 156.9	$ 280.9	$ 128.8	$ 707.9

Critical Accounting Policies, Estimates and Assumptions

Questar's significant accounting policies are described in Note 1 accompanying the consolidated financial statements included in Item 8 of this Form 10-K. The Company's consolidated financial statements are prepared in accordance with U.S. generally accepted accounting principles. The preparation of consolidated financial statements requires management to make assumptions and estimates that affect the reported results of operations and financial position. The following accounting policies may involve a higher degree of complexity and judgment on the part of management.

Successful-Efforts Accounting for Gas and Oil Operations

The Company follows the successful-efforts method of accounting for gas- and oil-property acquisitions, exploration, development and production activities. Under this method, the acquisition costs of proved and unproved properties, successful exploratory wells and development wells are capitalized. Other exploration costs, including geological and geophysical costs, the delay rental and administrative costs associated with unproved property and unsuccessful exploratory-well costs are expensed. Costs to operate and maintain wells and field equipment are expensed as incurred.

The capitalized costs of unproved properties are generally combined and amortized over the expected holding period for such properties. Individually significant unproved properties are periodically reviewed for impairment. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Capitalized proved-property-acquisition costs are amortized by field using the unit-of-production method based on proved reserves. Capitalized exploratory-well and development costs are amortized similarly by field based on proved-developed reserves. The calculation takes into consideration estimated future equipment dismantlement, surface restoration and property-abandonment costs, net of estimated equipment-salvage values. Other property and equipment are generally depreciated using the straight-line method over estimated useful lives or the unit-of-production method for certain processing plants. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production amortization rate would be significantly affected.

Questar E&P engages independent reservoir-engineering consultants to prepare estimates of the proved gas and oil reserves. Reserve estimates are based on a complex and highly interpretive process that is subject to continuous revision as additional production and development-drilling information becomes available.

Long-lived assets are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated on a field-by-field basis. If the undiscounted pretax cash flows are less than the net book value of the asset group, the asset value is written down to estimated fair value which is determined using discounted future net revenues.

Accounting for Derivatives

The Company uses derivative instruments, typically fixed-price swaps, to hedge against a decline in the realized prices of its gas and oil production. Accounting rules for derivatives require that these instruments be marked to fair value at the balance-sheet reporting date. The change in fair value is reported either in net income or comprehensive income depending on the structure of the derivatives. The Company has structured virtually all energy-derivative instruments as cash-flow hedges as defined in SFAS 133 as amended. Changes in the fair value of cash-flow hedges are recorded on the balance sheet and in comprehensive income or loss until the underlying gas or oil is produced. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production.

Revenue Recognition

Revenues are recognized in the period that services are provided or products are delivered. Questar E&P uses the sales method of accounting whereby revenue is recognized for all gas, oil and NGL sold to purchasers. Revenues include estimates for the two most recent months using published commodity index prices and volumes supplied by field operators. A liability is recorded to the extent that Questar E&P has an imbalance in excess of its share of remaining reserves in an underlying property. Energy-trading revenues are presented on a gross-revenue basis.

Questar Gas estimates revenues on a calendar basis even though bills are sent to customers on a cycle basis throughout the month. The company estimates unbilled revenues for the period from the date meters are read to the end of the month, using usage history and weather information. Approximately one-half month of revenues is estimated in any period. The gas costs and other variable costs are recorded on the same basis to ensure proper matching of revenues and expenses.

Questar Gas's tariff provides for monthly adjustments to customer charges to approximate the impact of normal temperatures on nongas revenues. Questar Gas estimates the weather-normalization adjustment for the unbilled revenue each month. The weather-normalization adjustment is evaluated each month and reconciled on an annual basis in the summer to agree with the amount billed to customers.

Rate Regulation

Regulatory agencies establish rates for the storage, transportation, distribution and sale of natural gas. The regulatory agencies also regulate, among other things, the extension and enlargement or abandonment of jurisdictional natural gas facilities. Regulation is intended to permit the recovery, through rates, of the cost of service, including a return on investment. Questar Gas and Questar Pipeline follow SFAS 71, "Accounting for the Effects of Certain Types of Regulation," that requires the recording of regulatory assets and liabilities by companies subject to cost-based regulation. The FERC, PSCU and PSCW have accepted the recording of regulatory assets and liabilities.

Employee Benefit Plans

The Company has pension and post-retirement-benefit plans covering a majority of its employees. The calculation of the Company's expense and liability associated with its benefit plans requires the use of a number of assumptions that the Company deems to be critical. Changes in these assumptions can result in different expenses and liabilities and actual experience can differ from these assumptions.

Independent consultants hired by the Company use actuarial models to calculate the yearly expenses of pension and post-retirement benefits. The models consider mortality estimations, liability discount rates, long-term rate of return on investments, rate of increase of compensation, amortizing gain or loss from investments and medical-cost trend rates among the key factors. Management makes assumptions based on parameters and advice from the consultants. The Company believes that the discount rate and the expected long-term rate of return on plan assets are critical assumptions.

The assumed discount rate reflects the current rate at which the pension benefits could effectively be settled. Management considered the rates of return on high-quality, fixed income investments and compared those results with a bond-defeasance technique. The Company discounted its future pension liabilities using rates of 6.50% and 6.75% as of December 31, 2004, and 2003, respectively. A 0.25% decrease in the discount rate increases the Company's annual expense by $1.3 million.

The expected long-term rate of return reflects the average rate of earnings expected on funds invested or to be invested in the pension plan to provide for the benefits included in the pension liability. The Company establishes the expected long-term rate of return at the beginning of each fiscal year giving consideration to the pension plan's investment mix and the historical and forecasted rates of return on these types of securities. The expected long-term rate of return determined by the Company as of January 1, 2004, and 2003, was 8.50%. Pension expense increases as the expected long-term rate of return decreases. A 0.25% decrease in the expected long-term rate of return causes a $0.6 million increase in the annual pension expense.

Recent Accounting Developments

Refer to Note 1 accompanying the consolidated financial statements in Item 8 for a discussion of recent accounting developments.

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

Questar's primary market-risk exposures arise from commodity-price changes for natural gas, oil and NGL, estimation of gas and oil reserves and volatility in interest rates. Energy Trading has long-term contracts for pipeline capacity and is obligated for transportation services with no guarantee that it will be able to recover the full cost of these transportation commitments.

Commodity-Price Risk Management

Market Resources bears the risk associated with commodity-price changes and uses gas- and oil-price-hedging arrangements in the normal course of business to limit the risk of adverse price movements. However these same arrangements typically limit future gains from favorable price movements. Hedging contracts are used for a significant share of Questar E&P-owned gas and oil production and for a portion of gas- and oil-marketing transactions and for some of Gas Management's NGL.

Market Resources has established policies and procedures for managing commodity-price risks through the use of derivatives. Natural gas- and oil-price hedging supports Market Resources' rate of return and cash-flow targets and protects earnings from downward movements in commodity prices. The volume of hedged production and the mix of derivative instruments are regularly evaluated and adjusted by management in response to changing market conditions and reviewed periodically by the Finance and Audit Committee of the Board of Directors. Market Resources may hedge up to 100% of forecast nonregulated production from proved-developed reserves when prices meet earnings and cash-flow objectives. Proved-developed production represents production from existing wells. Market Resources does not enter into derivative arrangements for speculative purposes and does not hedge undeveloped reserves or equity NGL.

Hedges are matched to equity gas and oil production, thus qualifying as cash-flow hedges under the accounting provisions of SFAS 133 as amended and interpreted. Gas hedges are typically structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. Any ineffective portion of hedges is immediately recognized in the income statement. The ineffective portion of hedges was not significant in 2004 and 2003.

As of December 31, 2004, approximately 74.3 bcf of forecast full-year 2005 gas production was hedged at an average price of $4.90 per Mcf, net to the well.

Market Resources enters into commodity-price-hedging arrangements with several banks and energy-trading firms. Generally the contracts allow some amount of credit before Market Resources is required to deposit collateral for out-of-the-money hedges. In some contracts the amount of credit varies depending on the credit rating assigned to Market Resources' debt. Market Resources' current ratings support individual counterparty lines of credit of $5 million to $40 million. If Market Resources credit ratings fall below investment grade (BBB- by Standard & Poor's or Baa3 by Moody's), counterparty credit generally falls to zero. In addition to the counterparty arrangements, Market Resources has a $200 million revolving-credit facility in place with banks.

A summary of Market Resources hedging positions for equity production as of December 31, 2004, is shown below. Prices are net to the well. Currently all hedges are fixed-price swaps with creditworthy counterparties, allowing Market Resources to achieve a known price for a specific volume of production delivered into a regional sales point. The swap price is then reduced by gathering costs and adjusted for product quality to determine the net-to-the-well price.

Time periods	Rocky Mountains	Midcontinent	Total	Rocky Mountains	Midcontinent	Total
	Gas (in bcf)			Average price per Mcf, net to the well		
First half of 2005	24.0	13.7	37.7	$ 4.73	$ 5.33	$ 4.95
Second half of 2005	23.6	13.0	36.6	4.65	5.23	4.86
12 months of 2005	47.6	26.7	74.3	4.69	5.28	4.90
First half of 2006	12.2	3.4	15.6	$ 4.96	$ 5.55	$ 5.09
Second half of 2006	12.4	3.5	15.9	4.96	5.55	5.09
12 months of 2006	24.6	6.9	31.5	4.96	5.55	5.09
First half of 2007	1.7		1.7	$ 5.08		$ 5.08
Second half of 2007	1.7		1.7	5.08		5.08
12 months 2007	3.4		3.4	5.08		5.08
	Oil (in Mbbl)			Average price per bbl, net to the well		
First half of 2005	362	181	543	$ 33.41	$ 34.70	$ 33.84
Second half of 2005	368	184	552	33.41	34.70	33.84
12 months of 2005	730	365	1,095	33.41	34.70	33.84

Market Resources held gas-price hedging contracts covering the price exposure for about 135.6 MMdth of gas, 1.1 MMbbl of oil and 3.8 MMgal of NGL as of December 31, 2004. A year earlier Market Resources' hedging contracts covered 148.1 MMdth of natural gas. Market Resources may hedge NGL prices in its processing business.

The following table summarizes changes in the fair value of hedging contracts from December 31, 2003, to December 31, 2004.

	(in thousands)
Net fair value of gas- and oil-hedging contracts outstanding at December 31, 2003	$ (49,098)
Contracts realized or otherwise settled	49,074
Increase in gas and oil prices on futures markets	(51,668)
Contracts added	(15,809)
Net fair value of gas- and oil-hedging contracts outstanding at December 31, 2004	$ (67,501)

A table of the net fair value of gas-hedging contracts as of December 31, 2004, is shown below. About 81% of the fair value of all contracts will settle and be reclassified from other comprehensive income in the next 12 months.

	(in thousands)
Contracts maturing by December 31, 2005	$ (54,845)
Contracts maturing between December 31, 2005, and December 31, 2006	(12,276)
Contracts maturing between December 31, 2006, and December 31, 2007	(380)
Net fair value of gas- and oil-hedging contracts at December 31, 2004	$ (67,501)

The following table shows sensitivity of the mark-to-market valuation of gas and oil price-hedging contracts to changes in the market price of gas and oil.

	At December 31,	
	2004	2003
	(in millions)	
Mark-to-market valuation asset (liability)	$ (67.5)	$ (49.1)
Value if market prices of gas and oil decline by 10%	2.5	1.3
Value if market prices of gas and oil increase by 10%	(137.5)	(99.5)

Credit Risk

Market Resources requests credit support and, in some cases, prepayment from companies with unacceptable credit risks. Market Resources' five largest customers are BP Energy, Sempra Energy Trading, Coral Energy Resources LP, ONEOK Energy Marketing and Virginia Power Energy. Sales to these companies accounted for 33% of Market Resources revenues in 2004 and their accounts were current at December 31, 2004.

Questar Pipeline requests credit support, such as letters of credit and cash deposits, from those companies that pose unfavorable credit risks. All companies posing such concerns were current on their accounts at December 31, 2004. Questar Pipeline's largest customers include Questar Gas, ChevronTexaco, Williams Energy Services, ConocoPhillips, PacifiCorp and Dominion Exploration and Production.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Financial Statements:

Report of Independent Registered Public Accounting Firm

Consolidated Statements of Income, three years ended December 31, 2004

Consolidated Balance Sheets at December 31, 2004 and 2003

Consolidated Statements of Common Shareholders' Equity, three years ended December 31, 2004

Consolidated Statements of Cash Flows, three years ended December 31, 2004

Notes accompanying Consolidated Financial Statements

Financial Statement Schedules:

For the three years ended December 31, 2004
Valuation and Qualifying Accounts

All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
Questar Corporation

We have audited the accompanying consolidated balance sheets of Questar Corporation and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Questar Corporation and subsidiaries at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Notes 1, 3 and 6 to the financial statements, Questar Corporation and subsidiaries adopted Statement of Financial Accounting Standards No. 142, *Goodwill and Other Intangible Assets* effective January 1, 2002 and Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, effective January 1, 2003.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Questar Corporation's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 3, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Ernst & Young LLP

Salt Lake City, Utah
March 3, 2005

QUESTAR CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2004	**2003**	**2002**
	(in thousands, except per share amounts)		
REVENUES			
Market Resources	$ 1,053,854	$ 751,502	$ 522,476
Questar Pipeline	67,844	74,981	66,275
Questar Gas	759,486	618,791	593,835
Corporate and other operations	20,247	17,914	18,081
TOTAL REVENUES	1,901,431	1,463,188	1,200,667
OPERATING EXPENSES			
Cost of natural gas and other products sold	840,544	542,441	395,742
Operating and maintenance	309,090	284,266	284,317
Depreciation, depletion and amortization	216,175	192,382	184,952
Questar Gas rate-refund obligation	4,090	24,939	
Exploration	9,239	4,498	6,086
Abandonment and impairment of gas, oil and other properties	15,758	4,151	11,183
Production and other taxes	90,948	70,681	44,192
TOTAL OPERATING EXPENSES	1,485,844	1,123,358	926,472
OPERATING INCOME	415,587	339,830	274,195
Interest and other income	6,868	7,435	56,667
Earnings from unconsolidated affiliates	5,125	5,008	11,777
Minority interest	(270)	222	501
Debt expense	(68,429)	(70,736)	(81,121)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECTS	358,881	281,759	262,019
Income taxes	129,580	102,563	91,126
INCOME BEFORE CUMULATIVE EFFECTS	229,301	179,196	170,893
Cumulative effect of accounting change for asset-retirement obligations, net of income taxes of $3,331		(5,580)	
Cumulative effect of accounting change for goodwill, net of $2,010 attributed to minority interest			(15,297)
NET INCOME	$ 229,301	$ 173,616	$ 155,596
BASIC EARNINGS PER COMMON SHARE			
Income before cumulative effects	$ 2.74	$ 2.17	$ 2.09
Cumulative effects		(0.07)	(0.19)
Net income	$ 2.74	$ 2.10	$ 1.90
DILUTED EARNINGS PER COMMON SHARE			
Income before cumulative effects	$ 2.67	$ 2.13	$ 2.07
Cumulative effects		(0.07)	(0.19)
Net income	$ 2.67	$ 2.06	$ 1.88
Weighted-average common shares outstanding			
Used in basic calculation	83,759	82,697	81,782

	Year Ended December 31,		
Used in diluted calculation	85,722	84,190	82,573

See notes accompanying consolidated financial statements

QUESTAR CORPORATION
CONSOLIDATED BALANCE SHEETS

	December 31,	
	2004	2003
	(in thousands)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 3,681	$ 13,905
Accounts receivable, net	262,373	221,954
Unbilled gas accounts receivable	59,160	49,722
Hedging collateral deposits		9,100
Fair value of hedging contracts	9,334	2,283
Inventories, at lower of average cost or market		
Gas and oil storage	66,944	40,305
Materials and supplies	18,993	12,184
Prepaid expenses and other	23,690	16,356
Purchased-gas adjustments	35,853	552
TOTAL CURRENT ASSETS	480,028	366,361
NET PROPERTY, PLANT AND EQUIPMENT successful efforts method of accounting for gas and oil properties	2,984,660	2,768,529
INVESTMENT IN UNCONSOLIDATED AFFILIATES	33,229	36,393
OTHER ASSETS		
Goodwill	71,260	71,260
Regulatory assets	32,120	37,839
Intangible pension asset	12,394	14,652
Fair value of hedging contracts	1,815	1,578
Other noncurrent assets	31,152	35,019
TOTAL OTHER ASSETS	148,741	160,348
	$ 3,646,658	$ 3,331,631

	December 31,	
	2004	2003
	(in thousands)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 68,000	$ 105,500

	December 31,	
Accounts payable and accrued expenses		
Accounts and other payables	282,562	181,012
Production and other taxes	49,779	40,124
Rate-refund obligations	25,343	24,939
Questar Gas customer credit balances	24,771	22,576
Interest	14,464	15,155
Federal income taxes	1,447	8,515
Deferred income taxes current	13,624	210
Total accounts payable and accrued expenses	411,990	292,531
Fair value of hedging contracts	64,179	51,137
Current portion of long-term debt	12	55,011
TOTAL CURRENT LIABILITIES	544,181	504,179
LONG-TERM DEBT, less current portion	933,195	950,189
DEFERRED INCOME TAXES	532,809	447,005
ASSET-RETIREMENT OBLIGATIONS	67,288	61,358
PENSION LIABILITY	32,640	31,617
POST-RETIREMENT BENEFITS	15,279	14,388
FAIR VALUE OF HEDGING CONTRACTS	14,471	1,822
OTHER LONG-TERM LIABILITIES	67,237	51,944
MINORITY INTEREST		7,864
COMMITMENTS AND CONTINGENCIES Note 12		
COMMON SHAREHOLDERS' EQUITY		
Common stock without par value; 350,000,000 shares authorized; 84,441,340 outstanding at December 31, 2004, and 83,233,951 outstanding at December 31, 2003	358,017	324,783
Retained earnings	1,135,718	977,780
Accumulated other comprehensive loss	(54,177)	(41,298)
TOTAL COMMON SHAREHOLDERS' EQUITY	1,439,558	1,261,265
	$ 3,646,658	$ 3,331,631

See notes accompanying consolidated financial statements

QUESTAR CORPORATION
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY

	Common Stock				
	Shares	Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Comprehensive Income (Loss)
	(dollars in thousands)				
Balances at January 1, 2002	81,523,407	$ 282,297	$ 772,408	$ 26,076	
Common stock issued	590,822	9,151			
Common stock repurchased	(60,469)	(1,594)			
2002 net income			155,596		$ 155,596

	Common Stock			Accumulated Other Comprehensive Income (Loss)	
Dividends paid ($0.725 per share)			(59,302)		
Income tax benefit associated with stock- ased compensation		1,642			
Adjustment of minority interest		6,093			
Amortization of nonvested stock		1,129			
Other comprehensive income					
Change in unrealized loss on energy hedges, net of income taxes of $25,651				(42,799)	(42,799)
Minimum pension liability, net of income taxes of $7,296				(11,779)	(11,779)
Unrealized loss on securities available for sale, net of income taxes of $2,005				(3,237)	(3,237)
Unrealized gain on interest-rate swaps, net of income taxes of $235				392	392
Foreign currency translation adjustment, net of income taxes of $2,375				2,688	2,688
Balances at December 31, 2002	82,053,760	298,718	868,702	(28,659)	$ 100,861
Common stock issued	1,293,439	21,855			
Common stock repurchased	(113,248)	(3,462)			
2003 net income			173,616		$ 173,616
Dividends paid ($0.78 per share)			(64,538)		
Income tax benefit associated with stock-based compensation		4,462			
Amortization of nonvested stock		2,041			
Acquisition of minority interest		1,169			
Other comprehensive income					
Change in unrealized loss on energy hedges, net of income taxes of $9,429				(15,755)	(15,755)
Minimum pension liability, net of income taxes of $1,930				3,116	3,116
Balances at December 31, 2003	83,233,951	324,783	977,780	(41,298)	$ 160,977
Common stock issued	1,335,103	29,145			
Common stock repurchased	(127,714)	(4,778)			
2004 net income			229,301		$ 229,301
Dividends paid ($0.85 per share)			(71,363)		
Income tax benefit associated with stock-based compensation		6,479			
Amortization of nonvested stock		2,388			
Other comprehensive income					
Change in unrealized loss on energy hedges, net of income taxes of $5,677				(9,515)	(9,515)
Minimum pension liability, net of income taxes of $2,084				(3,364)	(3,364)
Balances at December 31, 2004	84,441,340	$ 358,017	$ 1,135,718	$ (54,177)	$ 216,422

See notes accompanying consolidated financial statements

QUESTAR CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2004	**2003**	**2002**

	Year Ended December 31,		
	(in thousands)		
OPERATING ACTIVITIES			
Net income	$ 229,301	$ 173,616	$ 155,596
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation, depletion and amortization	225,879	201,809	194,369
Deferred income taxes and investment-tax credits	106,978	80,811	78,516
Amortization of nonvested stock	2,388	2,041	1,129
Abandonment and impairment of gas, oil and related properties	15,758	4,151	11,183
Net (gain) loss from asset sales	(336)	525	(43,683)
Impairment of partnership interest			2,956
Earnings from unconsolidated affiliates, net of cash distributions	3,164	1,974	2,257
Minority interest and other	286	(166)	(590)
Cumulative effect of accounting changes		5,580	15,297
	583,418	470,341	417,030
Changes in operating assets and liabilities			
Accounts receivable	(40,779)	(69,357)	14,488
Inventories	(33,448)	(12,144)	8,964
Prepaid expenses and other	(7,312)	(1,348)	(374)
Accounts payable and accrued expenses	96,883	25,900	(19,822)
Rate-refund obligations	404	24,939	
Federal income taxes	(1,432)	2,412	18,310
Purchased-gas adjustments	(35,301)	(13,834)	21,578
Other assets	1,277	2,977	10,399
Other liabilities	18,172	6,487	1,775
NET CASH PROVIDED FROM OPERATING ACTIVITIES	581,882	436,373	472,348
INVESTING ACTIVITIES			
Capital expenditures			
Purchase of property, plant and equipment	(441,483)	(309,928)	(339,320)
Other investments	(1,000)	(15,411)	(23,333)
Total capital expenditures	(442,483)	(325,339)	(362,653)
Proceeds from disposition of assets	7,121	10,975	280,645
NET CASH USED IN INVESTING ACTIVITIES	(435,362)	(314,364)	(82,008)
FINANCING ACTIVITIES			
Common stock issued	29,145	21,855	9,151
Common stock repurchased	(4,778)	(3,462)	(1,594)
Long-term debt issued		110,000	325,000
Long-term debt repaid	(71,993)	(249,990)	(179,120)
Increase (decrease) in short-term debt	(37,500)	56,500	(481,246)
Decrease in cash held in escrow			6,838
Other financing	(255)	(110)	272
Dividends paid	(71,363)	(64,538)	(59,302)
NET CASH USED IN FINANCING ACTIVITIES	(156,744)	(129,745)	(380,001)
Foreign-currency-translation adjustment			2
Change in cash and cash equivalents	(10,224)	(7,736)	10,341
Beginning cash and cash equivalents	13,905	21,641	11,300
Ending cash and cash equivalents	$ 3,681	$ 13,905	$ 21,641

See notes accompanying consolidated financial statements

QUESTAR CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Summary of Significant Accounting Policies

Nature of Business

Questar Corporation is a natural gas-focused energy company with three principal lines of business gas and oil exploration and production, interstate gas transmission, and retail gas distribution. Market Resources subsidiaries conduct gas and oil exploration, development and production, gas gathering and processing, wholesale gas and oil marketing, and gas storage. Questar Pipeline provides interstate natural gas transmission, storage and gas processing and treating services. Questar Gas conducts retail natural gas distribution.

Principles of Consolidation

The consolidated financial statements contain the accounts of Questar Corporation and subsidiaries. The consolidated financial statements were prepared in accordance with U.S. generally accepted accounting principles (GAAP) and with the instructions of Form 10-K and Regulations S-X and S-K. All significant intercompany accounts and transactions have been eliminated in consolidation.

Investments in Unconsolidated Affiliates

Questar uses the equity method to account for investments in affiliates where it does not have control. Generally, the Company's investment in these affiliates equals the underlying equity in net assets.

Use of Estimates

The preparation of consolidated financial statements and notes in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

Revenue Recognition

Market Resources recognizes revenues in the period that services are provided or products are delivered. Revenues reflect the impact of price-hedging instruments. Revenues are accounted for using the sales method, whereby revenue is recognized on all gas and oil sold to purchasers. A liability is recorded to the extent that the company has sold volumes in excess of its share of remaining reserves in an underlying property. The company's imbalance obligations at December 31, 2004, and 2003, were $3.0 million and $2.4 million, respectively. Energy-trading revenues are recognized on a gross basis.

Questar Gas records revenues for gas delivered to residential and commercial customers but not billed at the end of the accounting period. The impact of abnormal weather on gas-distribution earnings is significantly reduced by a weather-normalization adjustment. The straight fixed-variable rate design used by Questar Pipeline, which allows for recovery of substantially all fixed costs in the demand or reservation charge, reduces the earnings impact of volume changes on gas-transportation and storage operations. Rate-regulated companies may collect revenues subject to possible refunds and establish reserves pending final orders from regulatory agencies.

Regulation

Questar Gas is regulated by the Public Service Commission of Utah (PSCU) and the Public Service Commission of Wyoming (PSCW). The Idaho Public Utilities Commission has contracted with the PSCU for rate oversight of Questar Gas's operations in a small area of southeastern Idaho. Questar Pipeline is regulated by the Federal Energy Regulatory Commission (FERC). Market Resources through its subsidiary Clear Creek Storage Company, LLC, operates a gas-storage facility under the jurisdiction of the FERC. These regulatory agencies establish rates for the storage, transportation and sale of natural gas. The regulatory agencies also regulate, among other things, the extension and enlargement or abandonment of jurisdictional natural gas facilities. Regulation is intended to permit the recovery, through rates, of the cost of service, including a return on investment.

The financial statements of rate-regulated businesses are presented in accordance with regulatory requirements. Methods of allocating costs to time periods, in order to match revenues and expenses, may differ from those of other businesses because of cost-allocation methods used in establishing rates.

Purchased-Gas Adjustments

Questar Gas accounts for purchased-gas costs in accordance with procedures authorized by the PSCU and the PSCW. Purchased-gas costs that are different from those provided for in present rates are accumulated and recovered or credited through future rate changes. Questar Gas may hedge a portion of its natural gas supply to mitigate price fluctuations for gas-distribution customers. The benefits and the costs of hedging are included in the purchased-gas-adjustment account. The regulatory commissions allow Questar Gas to record periodic mark-to-market adjustments for commodity price-hedging contracts in the purchased-gas-adjustment account.

Other Regulatory Assets and Liabilities

Rate-regulated businesses may be permitted to defer recognition of certain costs, which is different from the accounting treatment required of nonrate-regulated businesses. Questar Gas recorded a regulatory asset at January 1, 2003, amounting to $6.6 million, representing a retroactive charge for the abandonment costs associated with gas wells operated on its behalf by Wexpro. The regulatory asset will be reduced over approximately 18 years following an amortization schedule or as cash is paid to plug and abandon wells. Gains and losses on the reacquisition of debt by rate-regulated companies are deferred and amortized as debt expense over either the would-be remaining life of the retired debt or the life of the replacement debt. The reacquired debt costs had a weighted-average life of approximately 12 years as of December 31, 2004. The cost of the early retirement windows offered to employees of rate-regulated subsidiaries was deferred and amortized over a five-year period, which will conclude in 2005. The rate-regulated businesses are allowed to recover certain deferred taxes from customers. Production taxes on cost-of-service gas production are recorded when the gas is produced and recovered from customers when taxes are paid, generally within 12 months. A liability has been recorded for postretirement medical costs allowed in rates that exceed actual costs.

Cash and Cash Equivalents

Cash equivalents consist principally of repurchase agreements with maturities of three months or less. In almost all cases, the repurchase agreements are highly liquid investments in overnight securities made through commercial-bank accounts that result in available funds the next business day.

Property, Plant and Equipment

Property, plant and equipment is stated at historical cost. Maintenance and repair costs are expensed as incurred.

Gas and oil properties

Questar E&P uses the successful-efforts method to account for gas and oil properties. The costs of acquiring leaseholds, drilling development wells, drilling successful exploratory wells, and purchasing related support equipment and facilities are capitalized under the successful-efforts method. The costs of unsuccessful exploratory wells are charged to expense when it is determined that such wells have not located proved reserves. Costs of geological and geophysical studies and other exploratory activities are expensed as incurred. Costs associated with production and general corporate activities are expensed in the period incurred. A gain or loss is generally recognized only when an entire field is sold or abandoned, or if the unit-of-production amortization rate would be significantly affected.

The capitalized costs of unproved properties are generally combined and amortized over the expected holding period for such properties. Individually significant unproved properties are periodically reviewed for impairment. Capitalized costs of unproved properties are reclassified as proved property when related proved reserves are determined or charged against the impairment allowance when abandoned.

Cost-of-service gas and oil operations

The successful-efforts method of accounting is used for "cost-of-service" gas and oil properties owned by Questar Gas and managed and developed by Wexpro, a subsidiary of Market Resources. Cost-of-service gas and oil properties are properties for which the operations and return on investment are subject to the Wexpro Agreement (see Note 15). In accordance with the agreement, production from the gas properties operated by Wexpro is delivered to Questar Gas at Wexpro's cost of providing this service. That cost includes a return on Wexpro's investment. Oil produced from the cost-of-service properties is sold at market prices. Proceeds are credited pursuant to the terms of the agreement, allowing Questar Gas to share in the proceeds for the purpose of reducing natural gas rates.

Depreciation, depletion and amortization

Capitalized proved-leasehold costs are depleted using the unit-of-production method based on proved reserves on a field basis. All other capitalized costs associated with gas and oil properties are depreciated using the unit-of-production method based on proved-developed reserves on a field basis. The Company capitalizes an estimate of the fair value of future abandonment costs, less estimated future salvage values, and depreciates those costs over the life of the related asset.

Average depreciation, depletion and amortization rates used in the 12 months ended December 31, were as follows.

	2004	2003	2002
Market Resources			
Gas and oil properties, per Mcfe			
United States	$ 1.02	$ 0.96	$ 0.91
Canada (in U.S. dollars)			0.98
Combined U.S. and Canada	1.02	0.96	0.92
Cost-of-service gas and oil properties, per Mcfe	0.69	0.65	0.64

For the remaining Company properties, the provision for depreciation, depletion and amortization is based upon rates that will systematically charge the costs of assets against income over the estimated useful lives of those assets. The investment in natural gas-gathering and processing facilities is charged to expense using either the straight-line or unit-of-production method. For depreciation purposes, major categories of fixed assets in the gas-distribution, transmission and storage operations are grouped together and depreciated on a straight-line method. Under the group method, salvage value is not considered when determining depreciation rates. Gains and losses on asset disposals are recorded as adjustments in accumulated depreciation. Gas-production facilities are depreciated using the unit-of-production method. The Company has not capitalized future- abandonment costs on a majority of its long-lived distribution and transmission assets due to a lack of a legal obligation to abandon the assets and to an indeterminable date of abandonment. If required, an obligation will be recognized when an abandonment date is known.

Average depreciation, depletion and amortization rates used in the 12 months ended December 31, were as follows.

	2004	2003	2002
Questar Pipeline transmission, processing and storage	3.4%	3.2%	3.2%
Questar Gas			
Distribution plant	3.7%	3.7%	3.9%
Gas wells, per Mcf	$ 0.11	$ 0.13	$ 0.14

Impairment of Long-Lived Assets

Proved gas and oil properties are evaluated on a field-by-field basis for potential impairment. Other properties are evaluated on a specific-asset basis or in groups of similar assets, as applicable. Impairment is indicated when a triggering event occurs and the sum of the estimated undiscounted future net cash flows of an evaluated asset is less than its carrying value. Triggering events could include an impairment of gas and oil reserves caused by mechanical problems, a faster-than-expected decline of reserves, lease-ownership issues, and/or an other-than-temporary decline in gas and oil prices. If impairment is indicated, fair value is calculated using a discounted-cash-flow approach. Cash-flow estimates require forecasts and assumptions for many years into the future for a variety of factors, including commodity prices and operating costs.

Goodwill and Other Intangible Assets

Intangible assets consist primarily of goodwill acquired through business combinations. Goodwill represents the excess of the cost over the fair value of net assets of acquired businesses. Goodwill is not amortized, but is tested for impairment at a minimum of once a year or when a triggering event occurs. Annual impairment tests are conducted in the fourth quarter. If a triggering event occurs, the undiscounted net cash flows of the asset or entity to which the goodwill relates are evaluated. Impairment is indicated if undiscounted cash flows are less than the carrying value of the assets. The amount of the impairment is measured using a discounted-cash-flow model considering future revenues, operating costs, a risk-adjusted discount rate and other factors.

Capitalized Interest and Allowance for Funds Used During Construction (AFUDC)

The Company capitalizes interest costs when applicable. Under provisions of the Wexpro Agreement, the company capitalizes AFUDC on cost-of-service construction projects. The FERC requires the capitalization of AFUDC during the construction period of rate-regulated plant and equipment. AFUDC amounted to $0.3 million in 2004, $1.1 million in 2003 and $3.5 million in 2002 and is included in Interest and Other Income in the Consolidated Statements of Income. Debt expense was reduced by $0.2 million, $0.1 million and $1.3 million in 2004, 2003 and 2002, respectively.

Hedging Instruments

The Company may elect to designate a derivative instrument as a hedge of exposure to changes in fair value, cash flows or foreign currencies. If the hedged exposure is a fair-value exposure, the gain or loss on the derivative instrument is recognized in earnings in the period of the change together with the offsetting gain or loss from the change in fair value of the hedged item. If the hedged exposure is a cash-flow exposure, the effective portion of the gain or loss on the derivative instrument is reported initially as a component of other comprehensive income and subsequently reclassified into earnings when the forecasted transaction affects earnings. Any amount excluded from the assessment of hedge effectiveness, as well as the ineffective portion of the gain or loss, is reported in earnings in the current period.

A derivative instrument qualifies as a cash-flow hedge if all of the following tests are met:

The item to be hedged exposes the Company to price risk.

The derivative reduces the risk exposure and is designated as a hedge at the time the Company enters into the contract.

At the inception of the hedge and throughout the hedge period, there is a high correlation between changes in the market value of the derivative instrument and the fair value of the underlying hedged item.

When the designated item associated with a derivative instrument matures, is sold, extinguished or terminated, derivative gains or losses are included in income in the same period that the underlying production or other contractual commitment is delivered. When a derivative instrument is associated with an anticipated transaction that is no longer probable, the gain or loss on the derivative is reclassified from other comprehensive income and recognized currently in the results of operations. When a derivative is terminated before its contract expires, the associated gain or loss is recognized in income over the life of the previously hedged production.

Physical Contracts: Physical-hedge contracts have a nominal quantity and a fixed price. Contracts representing both purchases and sales settle monthly based on quantities valued at a fixed price. Purchase contracts fix the purchase price paid and are recorded as cost of sales in the month the contracts are settled. Sales contracts fix the sales price received and are recorded as revenues in the month they are settled. Due to the nature of the physical market, there is a one-month delay for the cash settlement. Market Resources accrues for the settlement of contracts in the current month's revenues and cost of sales.

Financial Contracts: Financial contracts are contracts that are net settled in cash without delivery of product. Financial contracts also have a nominal quantity and exchange an index price for a fixed price, and are net settled with the brokers as the price bulletins become available. Financial contracts are recorded in cost of sales in the month of settlement.

Credit Risk

The Rocky Mountain and Midcontinent regions of the United States constitute the Company's primary market areas. Exposure to credit risk may be affected by the concentration of customers in these regions due to changes in economic or other conditions. Customers include individuals and numerous commercial and industrial enterprises that may react differently to changing conditions. Management believes that its credit-review procedures, loss reserves, customer deposits and collection procedures have adequately provided for usual and customary credit-related losses. Commodity-based hedging arrangements also expose the Company to credit risk. The Company monitors the creditworthiness of its counterparties, which generally are major financial institutions and energy companies. Loss reserves are periodically reviewed for adequacy and may be established on a specific-case basis. Market Resources requests credit support and, in some cases, fungible collateral from companies with unacceptable credit risks. The Company has a master-netting agreement with some customers that allows the offsetting of receivables and payables in a default situation.

Bad-debt expense amounted to $5.5 million, $3.7 million and $7.9 million for the years ended December 31, 2004, 2003 and 2002, respectively. The allowance for bad-debt expenses was $6.1 million and $6.7 million at December 31, 2004, and 2003, respectively. Questar Gas's retail-gas operations account for a majority of the bad-debt expense. Questar Gas estimates bad-debt expense as 0.9% of general-service revenues with periodic adjustments. Uncollected accounts are generally written off five months after gas is delivered and interest is no longer accrued.

Income Taxes

Questar and its subsidiaries file a consolidated federal income tax return. Deferred income taxes have been provided for temporary differences caused by differences between the book and tax-carrying amounts of assets and liabilities. These differences create taxable or tax-deductible amounts for future periods. Questar Gas and Questar Pipeline use the deferral method to account for investment-tax credits as required by regulatory commissions.

Earnings Per Share (EPS)

Basic earnings per share is computed by dividing net income available to common shareholders by the weighted-average number of common shares outstanding during the accounting period. Diluted EPS includes the potential increase in outstanding shares that could result from exercising in-the-money stock options plus the estimated number of non-vested restricted shares.

Stock-Based Compensation

The Company accounts for employee stock-based compensation using the intrinsic-value method prescribed by Accounting Principles Board Opinion (APBO) 25, "Accounting for Stock Issued to Employees," and related interpretations. No compensation expense is recorded because the exercise price of options equals the market price on the date of grant. Compensation expense for awards of restricted shares are valued at market price on the grant date and amortized over the vesting period. A table showing income adjusted for stock-based compensation follows.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Net income, as reported	$ 229,301	$ 173,616	$ 155,596
Deduct: Stock-based compensation expense determined under fair-value-based methods, net of income tax	(2,639)	(5,277)	(5,100)
Pro forma net income	$ 226,662	$ 168,339	$ 150,496
Earnings per share			
Basic, as reported	$ 2.74	$ 2.10	$ 1.90
Basic, pro forma	2.71	2.04	1.84
Diluted, as reported	2.67	2.06	1.88
Diluted, pro forma	2.64	2.00	1.82

Comprehensive Income

Comprehensive income is the sum of net income as reported in the Consolidated Statement of Income and other comprehensive income transactions reported in the Consolidated Statement of Common Shareholders' Equity. Other comprehensive income or loss is the result of changes in the market value of gas and oil cash-flow derivatives and recognition of additional pension liability. These transactions are not the culmination of the earnings process, but result from periodically adjusting historical balances to fair value. Income or loss is realized when the underlying energy product is sold and pension costs are accrued.

The balances of accumulated other comprehensive loss, net of income taxes, at December 31, were as follows.

	2004	2003
	(in thousands)	
Unrealized loss on energy-hedging transactions	$ (42,150)	$ (32,635)
Additional pension liability	(12,027)	(8,663)
Accumulated other comprehensive loss	$ (54,177)	$ (41,298)

Business Segments

Questar has three primary segments: Market Resources, Questar Pipeline and Questar Gas. Line-of-business information is presented according to senior management's basis for evaluating performance considering differences in the nature of products, services and regulation.

Certain intersegment sales include intercompany profit.

Recent Accounting Developments

The Financial Accounting Standards Board (FASB) concluded that all companies would be required to measure and record the costs for stock-based awards using estimated fair value on the date of grant. SFAS 123R "Share-Based Payments," issued in December 2004 applies to all equity-based awards granted, modified or settled for periods beginning July 1, 2005. Questar issues stock options and nonvested shares to employees and non-employee directors. Currently Questar accounts for stock options under the intrinsic-value method where no expense is recorded. SFAS 123R will require recognition of costs in the consolidated statement of income. Questar estimates that the impact of expensing the value of currently issued stock options is not material.

In February 2005, the FASB Staff posted its proposed FSP FAS 19-a, "Accounting for Suspended Well Costs." At issue is the current requirement of SFAS 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," to capitalize the costs of drilling exploratory wells pending determination of whether the well has found proved reserves. The capitalized costs become part of the entity's wells, equipment, and facilities if the well successfully located proved reserves. However, if the well has not found proved reserves, the capitalized costs of drilling the well are expensed, net of any salvage value. Questions have arisen as to whether there are circumstances that would permit the continued capitalization of exploratory-well costs beyond the one-year limit specified in SFAS 19 other than when additional exploration wells are necessary to justify major capital expenditures and those wells are underway or firmly planned for the near future. In its proposal, the FASB Staff states that exploratory well costs could be capitalized beyond a one-year limit if the well has found a sufficient quantity of reserves to justify its completion as a producing well and the entity is making progress assessing reserves and the economic and operational viability of the project. Comments on the proposed FASB Staff position are due March 7, 2005. The Company drills exploratory wells in the onshore United States in petroleum-producing regions with good access to downstream markets. Factors such as weather, seasonal access restrictions on federal land, or delays caused by permitting production facilities can cause minor delays in connecting successful exploratory wells to downstream markets, but those delays are typically less than one year. The Company currently has no completed exploratory wells classified as suspended.

In December 2004, the FASB issued SFAS 153 "Exchanges of Nonmonetary Assets, an amendment of APBO 29" to address the accounting for nonmonetary exchanges of productive assets. SFAS 153 amends APBO 29, "Accounting for Nonmonetary Exchanges," which established a narrow exception from fair-value measurement for nonmonetary exchanges of similar productive assets. SFAS 153 eliminates that exception and replaces it with an exception for exchanges that do not have commercial substance. Under SFAS 153 nonmonetary exchanges are required to be accounted for at fair value, recognizing any gains or losses, if their fair value is determinable within reasonable limits and the transaction has commercial substance. SFAS 153 specifies that a nonmonetary exchange has commercial substance if future cash flows of the entity are expected to change significantly as a result of the exchange. The provisions of SFAS 153 apply to nonmonetary asset exchanges in fiscal periods beginning after June 15, 2005. Adoption of SFAS 153 is not expected to have a material impact on Questar's financial position or results of operations.

Reclassifications

Certain reclassifications were made to prior-year consolidated financial statements to conform with the 2004 presentation of fair value hedging contracts, customer-credit balances, additional detail of other long-term liabilities and capital expenditure accruals.

Note 2 Rate-Refund Obligations

Questar Gas-Processing Dispute

On August 1, 2003, the Utah Supreme Court issued an order reversing an August 2000 decision made by the PSCU concerning certain natural gas-processing costs incurred by Questar Gas. The court ruled that the PSCU did not comply with its statutory responsibilities and regulatory procedures when approving a stipulation in Questar Gas's 1999 general rate case. The stipulation permitted Questar Gas to collect $5.0 million per year, a portion of the processing costs, through May 2004. The Committee of Consumer Services, a Utah state agency, appealed the PSCU's decision, arguing that the PSCU had failed to explicitly address whether the costs were prudent.

As a result of the court's order, Questar Gas recorded a liability for a potential refund to gas-distribution customers. A total liability of $29.0 million, including $4.1 million recorded in the first nine months of 2004, includes revenue received for processing costs and interest from June 1999 through September 2004.

On August 30, 2004, the PSCU ruled that Questar Gas failed in 1999 to prove that its decision to contract for gas processing with an affiliate was prudent. The PSCU rejected the stipulation, denied the request for rate recovery and ordered the refund of gas-processing costs previously collected in rates. Because Questar Gas had previously accrued a liability for the refund, the order did not have a material impact on 2004 earnings. Questar Gas reduced its rates on September 1, 2004, to eliminate the collection of gas-processing costs, and on October 1 began refunding previously collected costs, plus interest, over a 12-month period. As of December 31, 2004, Questar Gas had a liability of $20.6 million of remaining refunds to customers.

In response to a Questar Gas petition, the PSCU clarified that its order did not preclude recovery of ongoing and certain past-processing costs. Ongoing processing costs are approximately $6 million per year. Questar Gas has requested ongoing rate coverage for gas-processing costs in its pass-through filings, but is not currently collecting these costs in rates. The PSCU has conducted several technical conferences to determine what actions should be taken to manage the heat content of the gas supply. On January 31, 2005, Questar Gas filed a rate request with the PSCU to recover $5.7 million per year of gas-processing costs through its gas-balance account.

Questar Pipeline Fuel-Gas Reimbursement

During the fourth quarter of 2004, the FERC issued an order to Questar Pipeline in a case involving the annual fuel-gas reimbursement percentage (FGRP). As a result Questar Pipeline recorded a revenue reduction in 2004 of $4.7 million, which included $2.3 million for prior years, as a potential credit to customers. The FERC previously granted Questar Pipeline's request to increase the FGRP effective January 1, 2004. In its order, the FERC approved the FGRP but also ruled that Questar Pipeline is required to credit to transmission customers proceeds from the sale of natural gas liquids recovered from its hydrocarbon dew point facilities at the Clay Basin storage field in northeastern Utah Questar Pipeline has filed a request for rehearing with the FERC. Questar Pipeline believes that any credit to customers should be reduced by the plant's cost of service. Until the issue is resolved, Questar Pipeline will continue to accrue a potential liability equal to any liquid revenues from the dew point plant.

Questar Pipeline made an annual FGRP filing with the FERC on November 30, 2004, requesting an increase in the FGRP to 2.6%. On December 30, 2004, the FERC approved the request on an interim basis subject to refund and final resolution of the 2004 FGRP proceeding. Several shippers have filed comments with the FERC protesting the FGRP level.

Note 3 Asset-Retirement Obligations (ARO)

On January 1, 2003, Questar adopted SFAS 143 "Accounting for Asset Retirement Obligations." SFAS 143 addresses the financial accounting and reporting of the fair value of legal obligations associated with the retirement of tangible long-lived assets. The Company's ARO applies primarily to plugging and abandonment costs associated with gas and oil wells and certain other properties. The fair value of abandonment costs is estimated and depreciated over the life of the related assets. ARO are adjusted to present value each period through an accretion calculation using a credit-adjusted risk-free interest rate.

Changes in asset-retirement obligations for the 12 months ended December 31 were as follows.

	2004	2003
	(in thousands)	
Balance at January 1,	$ 61,358	$ 56,493
Accretion	2,868	3,667
Additions	3,159	2,268
Revisions	695	
Retirements and properties sold	(792)	(1,070)
Balance at December 31,	$ 67,288	$ 61,358

The accounting treatment of reclamation activities associated with ARO for properties administered under the Wexpro Agreement is spelled out in a guideline letter between Wexpro and the Utah Division of Public Utilities and the staff of the PSCW. Pursuant to the stipulation, Wexpro collects and deposits in trust certain funds related to estimated ARO costs. The funds are used to satisfy retirement obligations as the properties are abandoned. At December 31, 2004, approximately $2.9 million was held in this trust invested in a short-term bond index fund.

Excluding the cumulative effect of implementation, the pro forma net-income effect of the retroactive application of SFAS 143 as of January 1, 2002, would not have been material. The pro forma ARO as of January 1, 2002, was $53.2 million.

Note 4 Property, Plant and Equipment

The details of property, plant and equipment and accumulated depreciation, depletion and amortization follow.

	December 31,	
	2004	2003

	December 31,	
	(in thousands)	
Property, plant and equipment		
Market Resources		
Gas and oil properties		
Proved properties	$ 1,602,143	$ 1,315,330
Unproved properties, not being depleted	62,678	95,208
Support equipment and facilities	16,932	22,569
	1,681,753	1,433,107
Cost-of-service gas and oil properties	516,162	472,983
Gathering, processing and marketing	258,417	243,081
	2,456,332	2,149,171
Questar Pipeline	1,055,030	1,034,958
Questar Gas	1,315,537	1,240,553
Corporate and other operations	50,872	78,113
	4,877,771	4,502,795

Accumulated depreciation, depletion and amortization

Market Resources		
Gas and oil properties	600,366	501,825
Cost-of-service gas and oil properties	262,523	239,035
Gathering, processing and marketing	74,378	75,985
	937,267	816,845
Questar Pipeline	355,407	336,206
Questar Gas	572,290	532,747
Corporate and other operations	28,147	48,468
	1,893,111	1,734,266
Net Property, Plant and Equipment	$ 2,984,660	$ 2,768,529

Questar E&P proved and unproved leaseholds had a net book value of $361.9 million and $385.0 million at December 31, 2004, and 2003, respectively. The Company currently has no completed exploratory wells classified as unproved properties, not being depleted.

Note 5 Investment in Unconsolidated Affiliates

Questar, indirectly through subsidiaries, has interests in businesses accounted for on the equity basis. As of December 31, 2004, and 2003, these affiliates did not have debt obligations with third-party lenders. The principal business activities, form of organization and percentage ownership are listed below. Percentage of voting control and economic interest are identical. Canyon Creek Compression Co., a general partnership (15%) and Rendezvous Gas Services LLC, a limited-liability corporation (50%), are engaged in gathering and compressing natural gas. Overthrust Pipeline Co. and TransColorado Gas Transmission Co. conducted transportation activities. The remaining interest in Overthrust was acquired in 2002 and is included in the consolidated financial statements. TransColorado was sold in 2002. The remaining 50% interest in the Blacks Fork Gas Processing Co. was acquired in 2002.

Summarized results of the partnerships representing 100% interest are listed below.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Gas-gathering and processing partnerships			
Revenues	$ 16,857	$ 15,916	$ 25,490
Operating income	10,280	9,775	8,805
Income before income taxes	10,312	9,807	8,869
Current assets, at end of period	6,626	5,167	11,806
Noncurrent assets, at end of period	66,010	74,111	45,704
Current liabilities, at end of period	1,338	909	5,178
Noncurrent liabilities, at end of period	1,073	1,589	2,182
Transportation partnerships			
Revenues			$ 24,992
Operating income			14,732
Income before income taxes			14,791

Note 6 Goodwill and Other Intangible Assets

The Company adopted SFAS 142, "Goodwill and Other Intangible Assets," as of January 1, 2002, and performed an initial test that indicated an impairment of goodwill acquired by a subsidiary of Questar InfoComm. The impairment amounted to $17.3 million, of which $15.3 million, or $0.19 per diluted common share, was attributed to Questar InfoComm's share and reported as a cumulative effect of a change in accounting for goodwill. The remaining $2 million loss was attributed to minority shareholders. Net income reported for 2002 was $155.6 million, or $1.88 per diluted share, including a goodwill impairment. Net income was $170.9 million, or $2.07 per diluted share, before the goodwill impairment. Neither the impairment resulting from the change in accounting method nor the amortization of goodwill was deductible for income tax purposes.

The balance in goodwill in each line of business is listed below.

	Consolidated	Market Resources	Questar Pipeline	Questar Gas
	(in thousands)			
Balance at January 1, 2003	$ 71,133	$ 61,423	$ 4,058	$ 5,652
Adjustment	127		127	
Balance at December 31, 2003 and 2004	$ 71,260	$ 61,423	$ 4,185	$ 5,652

As of December 31, 2004, the Company held about $3.2 million of intangible assets with indefinite lives. Intangible assets, primarily rights of way for pipelines, subject to amortization, amounted to $11.2 million, net of accumulated amortization of $2.7 million. The weighted-average amortization period was 32 years.

Note 7 Other Regulatory Assets and Liabilities

In addition to purchased-gas adjustments, the Company has other regulatory assets and liabilities. The regulated entities recover these costs but do not receive a return on these assets. A list of regulatory assets follows.

	December 31,	
	2004	2003
	(in thousands)	
Cost of reacquired debt	$ 17,329	$ 17,954
Asset-retirement obligations cost-of-service gas wells	5,097	8,256

	December 31,	
Deferred production taxes	4,258	3,090
Early retirement costs	2,418	5,370
Income taxes recoverable from customers	1,276	3,010
Questar Gas pipeline-integrity costs	1,042	
Other	700	159
	$ 32,120	$ 37,839

Questar Pipeline has accrued a regulatory liability for the collection of postretirement medical costs allowed in rates which exceeded actual charges. The balance as of December 31 was $3.6 million in 2004 and $3.2 million in 2003. Questar Pipeline has a regulatory liability for a refund of income taxes to customers amounting to $0.6 million and $1.3 million at December 31, 2004, and 2003, respectively. The balance will be refunded to customers through 2016.

Note 8 Debt

The Company has short-term line-of-credit arrangements with several banks under which it may borrow up to $210 million. These credit lines have interest rates generally below the prime-interest rate. Commercial-paper borrowings with initial maturities of less than one year are backed by the short-term line-of-credit arrangements. The details of short-term debt are as follows.

	December 31,	
	2004	2003
	(in thousands)	
Commercial paper with variable-interest rates	$ 68,000	$ 105,500
Weighted-average interest rate	2.45%	1.11%

The details of long-term debt at December 31 are listed below. All notes and the revolving-credit loan are unsecured obligations and rank equally with all other unsecured liabilities. At December 31, 2004, Market Resources could pay a dividend of $334 million to the parent company without violating the terms of its debt covenants.

	December 31,	
	2004	2003
	(in thousands)	
Market Resources		
7.0% notes due 2007	$ 200,000	$ 200,000
7.5% notes due 2011	150,000	150,000
Revolving-credit loan		55,000
Questar Pipeline		
Medium-term notes 5.85% to 7.55%, due 2008 to 2018	310,400	310,400
Questar Gas		
Medium-term notes 5.02% to 7.58%, due 2007 to 2018	273,000	290,000
Corporate and other operations	112	123
Total long-term debt outstanding	933,512	1,005,523
Less current portion	(12)	(55,011)
Less unamortized-debt discount	(305)	(323)
	$ 933,195	$ 950,189

Maturities of long-term debt for the five years following December 31, 2004, are as follows.

	(in thousands)
2005	$ 12
2006	14
2007	210,016
2008	101,318
2009	20

Cash paid for interest was $66.8 million in 2004, $70.2 million in 2003 and $77.3 million in 2002.

On June 21, 2004, Questar Gas called $17 million in medium-term notes that carried an interest rate of 8.12%. A call premium of $0.7 million is being amortized over the remaining life of the original notes in accordance with regulatory treatment.

On March 19, 2004, Market Resources completed a $200 million credit facility with a consortium of banks that replaced an existing facility that would have expired in April 2004. The facility allows for floating-rate interest and revolving loans of various maturities until March 2009. Key financial covenants place limits on minimum levels of cash flow compared to interest expense and maximum amounts of debt as a percentage of total capital. The interest rate credit spread on borrowings varies with changes in Market Resources' credit rating, but a reduction in or loss of credit ratings does not trigger an event of default under the facility.

Note 9 Earnings Per Share (EPS) and Common Stock

Earnings per share

Basic EPS is computed by dividing net income available to common shareholders by the weighted-average number of common shares outstanding during the accounting period. Diluted EPS includes the potential increase in the number of outstanding shares that could result from the exercise of in-the-money stock options plus the estimated number of nonvested restricted shares. A reconciliation of the components of basic and diluted shares used in the EPS calculation follows.

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Weighted-average basic common shares outstanding	83,759	82,697	81,782
Potential number of shares issuable from exercising stock options and nonvested shares	1,963	1,493	791
Weighted-average diluted common shares Outstanding	85,722	84,190	82,573

In 2004, Questar issued shares under the terms of the Dividend Reinvestment and Stock Purchase Plan (Reinvestment Plan) and the Long-Term Stock Incentive Plan (LTSIP).

Reinvestment Plan

The Reinvestment Plan allows parties interested in owning Questar common stock to reinvest dividends or invest additional funds in common stock. The Company can issue new shares or buy shares in the open market to meet shareholders' purchase requests. The Reinvestment Plan issued total shares of 185,809, 208,400 and 112,761 in 2004, 2003 and 2002, respectively. At December 31, 2004, 1,193,945 shares were reserved for future issuance.

Employee Investment Plan (EIP)

The EIP allows eligible employees to purchase shares of Questar common stock or other investments through payroll deduction. The Company matches 80% of employees' pre-tax purchases up to a maximum of 6% of their qualifying earnings. In addition, each year the Company makes a nonmatching contribution of $200 to each eligible employee. The Company's expense equals its contribution. Questar's expense for the EIP amounted to $5.8 million, $5.5 million and $5.5 million for the years ended December 31, 2004, 2003 and 2002, respectively. The number of shares in the EIP increased by 143,436 shares, 176,626 shares and 61,010 shares in 2004, 2003 and 2002, respectively. Contributions to the EIP for part of 2002 were made through shares purchased on the open market.

Long-term Stock-Incentive Plan

The Company has an omnibus LTSIP for officers, directors, and employees. The current plan was amended March 1, 2001, and approved by shareholders to combine optionees under one plan and reserve an additional 8,000,000 shares. The Company's separate Stock Option Plan for Directors terminated, but still has outstanding options granted. Stock options for participants have 10-year terms. Options held by employees vest in four equal, annual installments beginning six months after grant. Options granted to nonemployee directors generally vest in one installment six months after grant. Options vest on an accelerated basis in the event of retirement and have post-retirement exercise periods. The option price equals the closing market price of the stock on the grant date; therefore no compensation expense is recorded. There were 5,856,016 shares available for future grant at December 31, 2004.

Transactions involving options in the stock plans are summarized as follows.

	Outstanding Options	Price Range	Weighted-Average Exercise Price
Balance at January 1, 2002	4,145,546	$9.81 - $28.01	$ 20.20
Granted	1,364,000	22.95 - 23.95	23.02
Cancelled	(53,600)	15.00 - 28.01	22.62
Exercised	(480,207)	9.81 - 22.95	16.57
Balance at December 31, 2002	4,975,739	13.69 - 28.01	21.29
Granted	1,156,500	27.11 - 29.71	27.18
Cancelled	(13,250)	22.95 - 28.01	26.29
Exercised	(1,138,770)	13.69 - 28.01	19.03
Balance at December 31, 2003	4,980,219	13.69 - 29.71	23.16
Granted	25,000	35.10	35.10
Cancelled	(11,000)	15.00 - 27.11	25.06
Exercised	(979,148)	13.69 - 35.10	20.62
Balance at December 31, 2004	4,015,071	$13.69 - $35.10	$ 23.85

	Options Outstanding			Options Exercisable	
Range of Exercise prices	Number outstanding December 31, 2004	Weighted-average remaining contract life in years	Weighted-average exercise price	Number exercisable December 31, 2004	Weighted-average exercise price
$13.69 - $17.00	687,000	4.5	$ 15.62	687,000	$ 15.62
19.13 - 23.95	1,339,284	5.9	22.44	1,127,534	22.32
27.11 - 35.10	1,988,787	7.2	27.64	1,528,287	27.67
	4,015,071		23.85	3,342,571	23.39

A fair value of the stock options issued was determined on the grant date using the Black-Scholes option-valuation model. The fair-value calculation relies upon subjective assumptions and the use of a mathematical model to estimate value and may not be representative of future results. The Black-Scholes model was intended for measuring the value of options traded on an exchange. The calculated fair value of options granted and major assumptions used in the model at the date of grant are listed below.

	2004	2003	2002
		(in thousands)	
Fair value of options at grant date	$ 9.66	$ 7.54	$ 6.58
Risk-free interest rate	3.52%	3.80%	4.98%

	2004	2003	2002
Expected price volatility	28.4%	30.0%	30.5%
Expected dividend yield	2.34%	2.70%	3.14%
Expected life in years	7.3	7.3	7.3

Nonvested Stock

The Company issued nonvested stock as part of bonus payments in specified situations. Compensation expense is recorded in the period that the bonus is earned. Shares of nonvested stock are also granted as sign-on bonuses and for retention purposes. Nonvested stock is granted under the terms of the LTSIP. These shares carry voting and dividend rights; however, sale or transfer is restricted. Distribution of nonvested stock and vesting periods were as follows.

	Year Ended December 31,		
	2004	**2003**	**2002**
Shares vesting in three to five years	132,400	160,201	44,091
Average market price per share at award date	$ 35.99	$ 29.15	$ 25.60
Compensation expense (in thousands)	$ 2,388	$ 2,041	$ 1,129

Shareholder Rights

On February 13, 1996, Questar's Board of Directors declared a stock-right dividend for each outstanding share of common stock. The stock rights were issued March 25, 1996. The rights become exercisable if a person, as defined, acquires 15% or more of the Company's common stock or announces an offer for 15% or more of the common stock. Each right initially represents the right to buy one share of the Company's common stock for $87.50. Once any person acquires 15% or more of the Company's common stock, the rights are automatically modified. Each right not owned by the 15% owner becomes exercisable for the number of shares of Questar's stock that have a market value equal to two times the exercise price of the right. This same result occurs if a 15% owner acquires the Company through a reverse merger when Questar and its stock survive. If the Company is involved in a merger or other business combination at any time after the rights become exercisable, rightholders will be entitled to buy shares of common stock in the acquiring Company having a market value equal to twice the exercise price of each right. The rights may be redeemed by the Company at a price of $.005 per right until 10 days after a person acquires 15% ownership of the common stock. The rights expire March 25, 2006.

Note 10 Financial Instruments and Risk Management

The carrying value and estimated fair values of Questar's financial instruments were as follows.

	December 31, 2004		December 31, 2003	
	Carrying Value	**Estimated Fair Value**	**Carrying Value**	**Estimated Fair Value**
	(in thousands)			
Financial assets				
Cash and cash equivalents	$ 3,681	$ 3,681	$ 13,905	$ 13,905
Gas and oil price-hedging contracts	11,149	11,149	3,861	3,861
Financial liabilities				
Short-term debt	$ 68,000	$ 68,000	$ 105,500	$ 105,500
Long-term debt	933,207	1,029,970	1,005,200	1,130,243
Gas and oil price-hedging contracts	78,650	78,650	52,959	52,959

The Company used the following methods and assumptions in estimating fair values.

Cash and cash equivalents and short-term debt the carrying amount approximates fair value.

Long-term debt the carrying amount of variable-rate debt approximates fair value. The fair value of fixed-rate debt is based on the discounted present value of cash flows using the Company's current borrowing rates.

Gas and oil price-hedging contracts fair value of the contracts is based on market prices as posted on the NYMEX from the last trading day of the year. The average price of the gas contracts at December 31, 2004, was $5.04 per MMBtu, representing the average of contracts with different terms including fixed, various "into-the-pipe" postings and NYMEX references. Price-hedging contracts were in place for equity-gas production and gas-marketing transactions. Gas hedges are structured as fixed-price swaps into regional pipelines, locking in basis and hedge effectiveness. Deducting transportation and heat-value adjustments on the hedges of equity gas as of December 31, 2004, would result in an average price of $4.96 per Mcf, net to the well. The average price for oil contracts at December 31, 2004 was $35.32 per bbl. Oil contracts related to equity production would result in a net-to-the-well price of $33.84 per bbl.

Market Resources held gas-price-hedging contracts covering the price exposure for about 135.6 million dth of natural gas 1.1 MMbbl of oil and 3.8 MMgal of NGL as of December 31, 2004. Gas Management, a subsidiary of Market Resources, uses forward-sales contracts to secure the price received for NGL processed from its plants. About 81% of those contracts will settle and be reclassified from other comprehensive income in 2005. A year earlier Market Resources hedging contracts covered 148.1 million dth of natural gas.

At December 31, 2004, the Company reported a liability, net of hedging assets, of $67.5 million from hedging activities. Settlement or realizations of contracts in 2004 resulted in a reduction of revenue of $49.1 million. The offset to the hedging liability, net of income taxes, was a $9.5 million unrealized loss on hedging activities recorded in other comprehensive loss in the shareholders' equity section of the balance sheet. Settlement of contracts resulted in reclassifying $15.7 million from comprehensive loss in 2003 and $42.4 million from comprehensive income in 2002 to the income statement. The ineffective portion of hedging transactions recognized in earnings was not significant. The fair-value calculation of gas- and oil-price hedges does not consider changes in the fair value of the corresponding scheduled equity physical transactions, (i.e., the correlation between index price and the price realized for the physical delivery of gas or oil.)

Note 11 Income Taxes

Details of Questar's income tax expense and deferred-income taxes are provided in the following tables. The components of income taxes were as follows.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Federal			
Current	$ 19,573	$ 20,166	$ 11,613
Deferred	97,582	76,356	60,409
State			
Current	1,544	383	(2,347)
Deferred	11,276	6,057	16,184
Deferred investment-tax credits	(395)	(399)	(401)
Foreign income taxes			5,668
	$ 129,580	$ 102,563	$ 91,126

The difference between the statutory federal income tax rate and the Company's effective income tax rate is explained as follows.

	Year Ended December 31,		
	2004	2003	2002
	Percentages		
Federal income taxes statutory rate	35.0%	35.0%	35.0%
Increase (decrease) as a result of: State income taxes, net of federal income tax benefit	2.3	1.5	3.4
Nonconventional fuel credits			(2.5)
Percentage depletion	(0.3)		
Amortize investment-tax credits related to rate-regulated assets	(0.1)	(0.1)	(0.2)
	0.2	0.3	0.4

	Year Ended December 31,		
Amortize unrecorded timing difference related to rate-regulated assets			
Tax benefits from dividends paid to ESOP	(0.4)	(0.5)	(0.5)
Foreign income taxes			(0.3)
Other	(0.6)	0.2	(0.5)
Effective income tax rate	36.1%	36.4%	34.8%

Significant components of the Company's deferred income taxes were as follows.

	December 31,	
	2004	2003
	(in thousands)	
Deferred-tax liabilities:		
Property, plant and equipment	$ 587,403	$ 498,498
Deferred-tax assets:		
Mark-to-market and hedging activities	25,335	18,361
Alternative minimum-tax credit carried forward	17,409	18,834
Employee benefits and compensation costs	11,850	12,966
Net operating loss carried forward		1,332
Total deferred tax assets	54,594	51,493
Deferred income taxes noncurrent	$ 532,809	$ 447,005
Deferred income taxes current liability:		
Purchased-gas adjustment	$ 13,624	$ 210

Cash paid for income taxes was $23.3 million and $18.9 million in 2004 and 2003, respectively. The Company received $8.8 million of refunded income taxes in 2002 resulting primarily from timing differences caused by intangible-drilling costs. Alternative minimum tax credits do not have an expiration date.

Note 12 Commitments and Contingencies

There are various legal proceedings against the Company and its affiliates. Management believes that the outcome of these cases will not have a material effect on the Company's financial position, operating results or liquidity. For more details refer to Item 3 of this report on Form 10-K.

Commitments

Historically, 40 to 50% of Questar Gas's gas-supply portfolio has been provided from company-owned gas reserves at the cost-of-service. The remainder of the gas supply has been purchased from more than 19 suppliers under approximately 57 gas-supply contracts using index-based or fixed pricing. Questar Gas has commitments of $142 million and $42 million to purchase gas in 2005 and 2006, respectively. Generally, at the conclusion of the heating season and after a bid process, new agreements for the upcoming heating season are put in place. Questar Gas bought natural gas under purchase agreements amounting to $336 million, $180 million and $148 million in 2004, 2003 and 2002, respectively. In addition, Questar Gas makes use of various storage arrangements to meet peak-gas demand during certain times of the heating season.

Questar Gas has third-party transportation commitments requiring yearly payments of $4.3 million through 2018.

Subsidiaries of Market Resources have contracted for firm-transportation services with various pipelines through 2018. Market conditions and competition may prevent full recovery of the cost. Annual payments and the years covered are as follows.

		(in millions)
2005	$	5.8
2006		5.7
2007		5.7
2008		5.3
2009		5.3
2010 through 2018	$	26.5

Questar sold its headquarters building under a sale-and-lease-back arrangement in November 1998. The operating agreement commits the Company to occupy the building through January 12, 2012. Questar has four renewal options of five years each, following expiration of the original lease in 2012.

On January 12, 2012, the lessor is required to pay Questar a lease-reduction payment of $12.1 million. On the following day Questar is required to pay a balloon-lease payment of $14.1 million. If the lessor does not make the lease-reduction payment on January 12, 2012, a lessor-nonpayment event occurs, and Questar's lease immediately extends for a period of 20 years with no additional rent due. Minimum future payments under the terms of long-term operating leases for the Company's primary office locations, are as follows.

		(in millions)
2005	$	5.1
2006		4.9
2007		4.6
2008		4.2
2009		3.9
2010 through 2012	$	21.9

Total minimum future-rental payments have not been reduced for sublease rentals of $144,000 in 2005, $145,000 in 2006, $120,000 in 2007, $94,000 in 2008 and $95,000 in 2009. Total rental expense amounted to $5.2 million in 2004 and 2003 and $4.9 million in 2002. Sublease-rental receipts were $176,000 in 2004, $287,000 in 2003 and $206,000 in 2002.

Note 13 Rate Regulation and Other Matters

State Rate Regulation

Questar Gas files periodic applications with the PSCU and PSCW requesting permission to reflect annualized gas-cost increases or decreases in its rates. Gas costs are passed on to customers on a dollar-for-dollar basis with no markup. Effective October 1, 2004, the PSCU and PSCW authorized Questar Gas to increase customer rates by about 10% to reflect higher projected gas costs and to recover the balance in the purchase-gas-adjustment account.

2002 General Rate-Case Order

Effective December 30, 2002, the PSCU issued an order approving an $11.2 million general-rate increase for Questar Gas using an 11.2% rate of return on equity. The rate increase was based on November 2002 usage per customer and costs.

FERC Order 2004

FERC Order No. 2004, which defines standards of conduct for transmission providers, became effective on September 22, 2004. These standards of conduct are designed to ensure that employees engaged in transmission system operations function independently from employees of marketing and energy affiliates. In addition, a transmission provider must treat all transmission customers on a non-discriminatory basis and must not operate its transmission system to preferentially benefit its marketing or energy affiliates. Questar Pipeline has determined that all Market Resources subsidiaries except Gas Management are marketing or energy affiliates. Questar Gas is not an energy affiliate. Questar Pipeline and other Questar companies have adopted new procedures to comply with this order.

Note 14 Employee Benefits

Pension Plan

The Company has defined-benefit pension and postretirement medical and life insurance plans covering the majority of its employees. The Company's Employee Benefits Committee (EBC) has oversight over investment of retirement-plan and postretirement-benefit assets. The EBC uses a third-party consultant to assist in setting targeted-policy ranges for the allocation of assets among various investment categories. The majority of retirement-benefit assets were invested as follows.

	Actual Allocation		
	December 31, 2004	December 31, 2003	Policy Range
Domestic equity securities	52%	51%	45% - 55%
Foreign equity securities	10%	8%	6% - 14%
Debt securities	32%	33%	32% - 42%
Real estate securities	6%	5%	3% - 7%
Other		3%	0% - 3%

Questar sets aside funds for retirement-benefit obligations to pay benefits currently due and to build asset balances over a reasonable time period to pay future obligations. Questar is subject to and complies with minimum-required and maximum-allowed annual contribution levels mandated by the Employee Retirement Income Security Act (ERISA) and by the Internal Revenue Code. Subject to the above limitations, the Company seeks to fund the qualified retirement plan approximately equal to the yearly expense. The majority of assets set aside for postretirement-benefit obligations are assets commingled with those of the Company's ERISA-qualified retirement plan as permitted by section 401(h) of the Internal Revenue Code. The retirement plan (including commingled 401(h) assets within the plan) seeks investment returns consistent with reasonable and prudent levels of liquidity and risk.

The EBC allocates pension-plan and postretirement-medical-plan assets among broad asset categories and reviews the asset allocation at least annually. Asset-allocation decisions consider risk and return, future-benefit requirements, participant growth and other expected cash flows. These characteristics affect the level, risk and expected growth of postretirement-benefit assets.

The EBC uses asset-mix guidelines that include targets and permissible ranges for each asset category, return objectives for each asset group and the desired level of diversification and liquidity. These guidelines change from time to time based on an ongoing evaluation of each plan's risk tolerance.

Responsibility for individual security selection rests with each investment managers, who are subject to guidelines specified by the EBC. These guidelines are designed to ensure consistency with overall plan objectives.

The EBC sets performance objectives for each investment manager that are expected to be met over a three-year period or a complete market cycle, whichever is shorter. Performance and risk levels are regularly monitored to confirm policy compliance and that results are within expectations.

Pension-plan guidelines prohibit transactions between a fiduciary and parties in interest unless specifically provided for in ERISA. No restricted securities, such as letter stock or private placements, may be purchased for any investment fund. Questar securities may be considered for purchase at an investment manager's discretion, but within limitations prescribed by ERISA and other laws. There is no direct investment in Questar shares for the periods disclosed. Use of derivative securities by any investment managers is prohibited except where the committee has given specific approval or where commingled funds are utilized which have previously adopted permitting guidelines.

Pension-plan benefits are based on the employee's age at retirement, years of service and highest earnings in a consecutive 72 semimonthly pay period during the 10 years preceding retirement. Continued lower interest rates resulted in the Company recording an additional pension liability of $31.9 million and a $12.4 million intangible-pension asset in 2004.

A summary of pension expense is as follows.

	Year Ended December 31,		
	2004	2003	2002
		(in thousands)	
Service cost	$ 8,077	$ 7,608	$ 6,770
Interest cost	19,429	18,289	17,400
Expected return on plan assets	(18,841)	(17,758)	(18,187)
Prior service and other costs	1,922	1,922	1,922
Recognized net-actuarial loss	2,105	904	

	Year Ended December 31,		
Amortization of early retirement costs	2,875	3,241	3,504
Pension expense	$ 15,567	$ 14,206	$ 11,409

Assumptions at the beginning of the year used to calculate pension expense for the year were as follows.

	2004	2003	2002
Discount rate	6.75%	7.00%	7.50%
Rate of increase in compensation	4.00%	4.00%	4.50%
Long-term return on assets	8.50%	8.50%	9.00%

The projected-benefit obligation was measured using a discount rate of 6.5% and 6.75% at December 31, 2004, and 2003, respectively. Changes in discount rates are included in changes in plan assumptions. Asset-return assumptions are based on historical returns tempered for expectations of future performance.

Pension Plan	**2004**	**2003**
	(in thousands)	
Change in benefit obligation		
Projected benefit obligation at January 1,	$ 292,501	$ 270,290
Service cost	8,077	7,608
Interest cost	19,429	18,289
Change in plan assumptions	12,214	11,046
Actuarial (gain) loss	993	(3,376)
Benefits paid	(11,470)	(11,356)
Projected benefit obligation at December 31,	321,744	292,501
Change in plan assets		
Fair value of plan assets at January 1,	207,109	173,202
Actual return on plan assets	21,499	31,057
Contributions to the plan	15,567	14,206
Benefits paid	(11,470)	(11,356)
Fair value of plan assets at December 31,	232,705	207,109
Plan assets less-than-projected benefit obligation	(89,039)	(85,392)
Unrecognized net-actuarial loss	79,979	71,535
Unrecognized prior-service cost	11,639	13,562
Accrued pension cost	2,579	(295)
Accrued supplemental executive-retirement plan cost	(3,348)	(2,641)
Additional pension liability	(31,871)	(28,681)
Pension liability	$ (32,640)	$ (31,617)

The accumulated-benefit obligation for the defined-benefit pension plan was $265.3 million and $238.7 million at December 31, 2004, and 2003, respectively. Pension-plan payments for the five years following 2004 and the subsequent five years aggregated are as follows.

	(in millions)
2005	$ 13.1
2006	13.1

		(in millions)
2007		12.1
2008		12.5
2009		13.1
2010 through 2014	$	84.0

Postretirement Benefits Other Than Pensions

Postretirement health-care benefits and life insurance are provided only to employees hired before January 1, 1997. The Company pays a portion of the costs of health-care benefits as determined by an employee's years of service and generally limited to 170% of the 1992 contribution for employees who retired after January 1, 1993. The Company is amortizing its transition obligation over a 20-year period, which began in 1992.

A summary of the expense of postretirement benefits other than pensions is listed below. Expenses include an estimate of the effect of the Medicare Prescription Drug, Improvement and Modernization Act of 20031. The drug benefit offered as part of postretirement medical coverage is actuarially equivalent to Part D of Medicare. The Company, however, has not decided whether to integrate coverage with Part D or maintain its current coverage.

	Year Ended December 31,		
	2004	2003	2002
	(in thousands)		
Service cost	$ 784	$ 787	$ 749
Interest cost	5,217	5,303	5,351
Expected return on plan assets	(3,049)	(2,602)	(3,137)
Amortization of transition obligation	1,878	1,877	1,877
Amortization of losses	321	481	
Special-termination benefits	165		
Accretion of regulatory liability	800	800	800
Postretirement benefit expense	$ 6,116	$ 6,646	$ 5,640

Assumptions at the beginning of the year used to calculate postretirement-benefit expense for the year were as follows.

	2004	2003	2002
Discount rate	6.75%	7.00%	7.50%
Long-term return on assets	8.50%	8.50%	9.00%
Health-care inflation rate decreasing to 6.5% by 2009	9.00%	9.50%	9.50%

Service costs and interest costs are sensitive to changes in the health-care inflation rate. A 1% increase in the health-care inflation rate would increase the yearly service and interest costs by $165,000 and the accumulated postretirement-benefit obligation by $2.4 million. A 1% decrease in the health-care inflation rate would decrease the yearly service cost and interest cost by $146,000 and the accumulated postretirement-benefit obligation by $2.2 million.

	2004	2003
	(in thousands)	
Postretirement Benefits Other Than Pensions		
Change in benefit obligation		
Projected benefit obligation at January 1,	$ 81,122	$ 78,944
Service cost	784	787
Interest cost	5,217	5,303
Actuarial loss	1,756	947
Special termination benefits	165	
Benefits paid	(5,358)	(4,859)

	2004	2003
Projected-benefit obligation at December 31,	83,686	81,122
Change in plan assets		
Fair value of plan assets at January 1,	35,866	30,923
Actual gain on plan assets	3,552	4,825
Contributions to the plan	4,425	4,977
Benefits paid	(5,358)	(4,859)
Fair value of plan assets at December 31,	38,485	35,866
Projected-benefit obligation in excess of plan assets	(45,201)	(45,256)
Unrecognized-transition obligation	15,020	16,898
Unrecognized net loss	14,902	13,970
Accrued postretirement-benefit cost	$ (15,279)	$ (14,388)

Postretirement-benefit payments for the five years following 2004 and the subsequent five years aggregated are as follows.

	(in millions)
2005	$ 5.6
2006	5.7
2007	5.5
2008	5.6
2009	5.6
2010 through 2014	$ 29.4

Postemployment Benefits

The Company recognizes the net present value of the liability for postemployment benefits, such as long-term disability benefits and health-care and life-insurance costs, when employees become eligible for such benefits. Postemployment benefits are paid to former employees after employment has been terminated but before retirement benefits are paid. The Company accrues both current and future costs. Questar's postemployment liability at December 31, 2004, 2003 and 2002, was $1.5 million, $1.7 million and $1.5 million, respectively.

Assumptions used to calculate postemployment-benefit liability were as follows.

	2004	2003	2002
Discount rate	6.50%	6.75%	7.00%
Health-care inflation rate decreasing to 6.5% by 2009	9.00%	9.50%	9.50%

Note 15 Wexpro Agreement

Wexpro's operations are subject to the terms of the Wexpro Agreement. The agreement was effective August 1, 1981, and sets forth the rights of Questar Gas's utility operations to share in the results of Wexpro's operations. The agreement was approved by the PSCU and PSCW in 1981 and affirmed by the Supreme Court of Utah in 1983. Major provisions of the agreement are as follows.

a. Wexpro continues to hold and operate all oil-producing properties previously transferred from Questar Gas's nonutility accounts. The oil production from these properties is sold at market prices, with the revenues used to recover operating expenses and to give Wexpro a return on its investment. The after-tax rate of return is adjusted annually and is approximately 13.2%. Any net income remaining after recovery of expenses and Wexpro's return on investment is divided between Wexpro and Questar Gas, with Wexpro retaining 46%.

b. Wexpro conducts developmental oil drilling on productive oil properties and bears any costs of dry holes. Oil discovered from these properties is sold at market prices, with the revenues used to recover operating expenses and to give Wexpro a return on its investment in successful wells. The after-tax rate of return is adjusted annually and is approximately 18.2%. Any net income remaining after recovery of expenses and Wexpro's return on investment is divided between Wexpro and Questar Gas, with Wexpro retaining 46%.

c. Amounts received by Questar Gas from the sharing of Wexpro's oil income are used to reduce natural-gas costs to utility customers.

d. Wexpro conducts gas-development drilling on productive gas properties and bears any costs of dry holes. Natural gas produced from successful drilling is owned by Questar Gas. Wexpro is reimbursed for the costs of producing the gas plus a return on its investment in successful wells. The after-tax return allowed Wexpro is approximately 21.2%.

e. Wexpro operates natural-gas properties owned by Questar Gas. Wexpro is reimbursed for its costs of operating these properties, including a rate of return on any investment it makes. This after-tax rate of return is approximately 13.2%.

Wexpro's investment base, net of depreciation and deferred income taxes, and the yearly average rate of return for 2004 and the previous two years are shown in the table below.

	2004	2003	2002
Wexpro's net investment base (in millions)	$ 182.8	$ 172.8	$ 164.5
Annual average rate of return (after tax)	19.7%	19.8%	20.5%

Note 16 Dispositions and Acquisitions

Sale of Canadian Properties

In October 2002 Market Resources sold its Canadian exploration and production subsidiary and recorded a pretax gain of $19.7 million. Total consideration received was $101.6 million.

Sale of TransColorado

On October 20, 2002, Questar Pipeline sold Questar TransColorado, Inc., the company owning Questar's interest in the TransColorado Pipeline, for $105.5 million.

Partnership Interests Acquired

In 2002 Questar Pipeline and affiliates acquired the final 28% partnership interests in the Overthrust Pipeline Company for $5.4 million.

Market Resources, through an affiliate, acquired the remaining 50% interest in the Blacks Fork processing plant effective December 18, 2002.

Note 17 Operations by Line of Business

Questar has three primary reportable segments: Market Resources, Questar Pipeline and Questar Gas. Line-of-business information is presented according to senior management's basis for evaluating performance including differences in the nature of products, services and regulation. Line-of-business disclosures and discussions were reorganized in 2003 and prior years to combine "Other Questar Regulated Services" information with Corporate and other operations. Information-technology operations were transferred from Corporate and other operations to affiliates.

Following is a summary of operations by line of business for the Year Ended December 31.

	Questar Consolidated	Intercompany Transactions	Market Resources	Questar Pipeline	Questar Gas	Corporate and other operations
	(in thousands)					
2004						
Revenues						
From unaffiliated customers	$ 1,901,431		$ 1,053,854	$ 67,844	$ 759,486	$ 20,247

	Questar Consolidated	Intercompany Transactions	Market Resources	Questar Pipeline	Questar Gas	Corporate and other operations
From affiliated companies		($ 240,167)	131,427	88,635	4,707	15,398
Total revenues	1,901,431	(240,167)	1,185,281	156,479	764,193	35,645
Operating expenses						
Cost of natural gas and other products sold	840,544	(219,913)	518,437		536,128	5,892
Operating and maintenance	309,090	(15,552)	144,668	55,654	104,786	19,534
Depreciation, depletion and amortization	216,175		142,688	28,235	41,956	3,296
Questar Gas rate-refund obligation	4,090				4,090	
Exploration	9,239		9,239			
Abandonment and impairment of gas, oil and related properties	15,758		15,758			
Other taxes and expenses	90,948	(4,702)	77,945	6,557	9,767	1,381
Total operating expenses	1,485,844	(240,167)	908,735	90,446	696,727	30,103
Operating income	415,587		276,546	66,033	67,466	5,542
Interest and other income	6,868	(2,891)	2,510	202	3,508	3,539
Earnings from unconsolidated affiliates	5,125		5,125			
Minority interest	(270)		(270)			
Debt expense	(68,429)	2,891	(27,412)	(22,242)	(19,733)	(1,933)
Income tax expense	(129,580)		(91,088)	(16,397)	(19,780)	(2,315)
Net income	$ 229,301		$ 165,411	$ 27,596	$ 31,461	$ 4,833
Identifiable assets	$ 3,646,658		$ 1,849,287	$ 743,879	$ 1,000,897	$ 52,595
Investment in unconsolidated affiliates	33,229		33,229			
Capital expenditures	442,483		332,806	30,063	77,040	2,574
2003						
Revenues						
From unaffiliated customers	$ 1,463,188		$ 751,502	$ 74,981	$ 618,791	$ 17,914
From affiliated companies		($ 231,766)	117,506	81,857	2,204	30,199
Total revenues	1,463,188	(231,766)	869,008	156,838	620,995	48,113

Operating expenses						
Cost of natural gas and other products sold	542,441	(199,209)	342,476		394,523	4,651
Operating and maintenance	284,266	(30,358)	130,680	53,249	100,279	30,416
Depreciation, depletion and amortization	192,382		121,316	26,141	40,126	4,799
Exploration	4,498		4,498			
Questar Gas rate-refund obligation	24,939				24,939	
Abandonment and impairment of gas, oil and related properties	4,151		4,151			
Other taxes and expenses	70,681	(2,199)	55,542	6,352	9,743	1,243
Total operating expenses	1,123,358	(231,766)	658,663	85,742	569,610	41,109
Operating income	339,830		210,345	71,096	51,385	7,004
Interest and other income (loss)	7,435	(3,435)	2,851	(426)	3,228	5,217
Income from unconsolidated affiliates	5,008		5,008			
Minority interest	222		183			39
Debt expense	(70,736)	3,435	(28,158)	(22,622)	(20,984)	(2,407)
Income tax expense	(102,563)		(69,126)	(17,746)	(13,113)	(2,578)
Income before accounting change	179,196		121,103	30,302	20,516	7,275
Cumulative effect of accounting change for asset retirement obligations	(5,580)		(5,113)	(133)	(334)	
Net income	$ 173,616		$ 115,990	$ 30,169	$ 20,182	$ 7,275
Identifiable assets	$ 3,331,631		$ 1,612,208	$ 746,535	$ 907,054	$ 65,834
Investment in unconsolidated affiliates	36,393		36,393			
Capital expenditures	325,339		226,761	23,787	71,383	3,408
2002						
Revenues						
From unaffiliated customers	$ 1,200,667		$ 522,476	$ 66,275	$ 593,835	$ 18,081
From affiliated companies		($ 217,067)	106,647	76,600	1,676	32,144
Total revenues	1,200,667	(217,067)	629,123	142,875	595,511	50,225
Operating expenses						
Cost of natural gas and other products sold	395,742	(183,051)	202,132		370,294	6,367
Operating and maintenance	284,317	(32,340)	131,598	49,593	105,544	29,922
Depreciation, depletion and amortization	184,952		117,446	22,149	39,771	5,586
Exploration	6,086		6,086			
Abandonment and impairment of gas, oil and related properties	11,183		11,183			
	44,192	(1,676)	30,234	4,948	9,548	1,138

Other taxes and expenses						
Total operating expenses	926,472	(217,067)	498,679	76,690	525,157	43,013
Operating income	274,195		130,444	66,185	70,354	7,212
Interest and other income	56,667	(6,058)	50,894	515	2,329	8,987
Income from unconsolidated affiliates	11,777		3,977	7,800		
Minority interest	501		484			17
Debt expense	(81,121)	6,058	(34,705)	(23,995)	(22,495)	(5,984)
Income tax expense	(91,126)		(53,165)	(17,897)	(17,789)	(2,275)
Income before accounting change	170,893		97,929	32,608	32,399	7,957
Cumulative effect of accounting change for goodwill	(15,297)					(15,297)
Net income (loss)	$ 155,596		$ 97,929	$ 32,608	$ 32,399	($ 7,340)
Identifiable assets	$ 3,084,983		$ 1,415,871	$ 744,855	$ 848,544	$ 75,713
Investment in unconsolidated affiliates	23,617		23,617			
Capital expenditures	362,653		185,990	100,707	72,019	3,937

Prior to its sale in the fourth quarter of 2002, Market Resources' Canadian subsidiary reported revenues, measured in U. S. dollars, totaling $21.7 million for the year ended December 31, 2002.

Note 18 Quarterly Financial and Stock-Price Information (Unaudited)

Following is a summary of quarterly financial and stock-price data.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
	(dollars in thousands, except per-share amounts)				
2004					
Revenues	$ 563,616	$ 369,515	$ 360,225	$ 608,075	$ 1,901,431
Operating income	136,790	82,297	71,800	124,700	415,587
Net income	76,133	42,556	36,941	73,671	229,301
Basic earnings per common share	0.91	0.51	0.44	0.88	2.74
Diluted earnings per common share	0.89	0.50	0.43	0.85	2.67
Dividends per common share	0.205	0.215	0.215	0.215	0.85
Market price per common share					
High	$ 37.08	$ 38.88	$ 46.40	$ 52.12	$ 52.12
Low	33.82	34.26	37.83	45.00	33.82
Close	$ 36.44	$ 38.64	$ 45.82	$ 50.96	$ 50.96
Price-earnings ratio on closing price					19.1
Annualized dividend yield on closing price	2.3%	2.2%	1.9%	1.7%	1.7%
Market-to-book ratio on closing price					2.99

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year
Average number of common shares traded per day (000)	221	225	374	336	290
2003					
Revenues	$ 469,804	$ 270,669	$ 273,503	$ 449,212	$ 1,463,188
Operating income	127,875	45,895	58,845	107,215	339,830
Net income before accounting change	70,202	20,272	28,691	60,031	179,196
Net income	64,622	20,272	28,691	60,031	173,616
Basic earnings per common share before accounting change	$ 0.86	$ 0.24	$ 0.35	$ 0.72	$ 2.17
Basic earnings per common share	0.79	0.24	0.35	0.72	2.10
Diluted earnings per common share before accounting change	$ 0.84	$ 0.24	$ 0.34	$ 0.71	$ 2.13
Diluted earnings per common share	0.77	0.24	0.34	0.71	2.06
Dividends per common share	0.185	0.185	0.205	0.205	0.78
Market price per common share					
High	$ 29.85	$ 34.12	$ 33.99	$ 35.50	$ 35.50
Low	26.04	29.35	30.11	30.75	26.04
Close	$ 29.57	$ 33.47	$ 30.81	$ 35.15	$ 35.15
Price-earnings ratio on closing price					17.1
Annualized dividend yield on closing price	2.5%	2.2%	2.7%	2.3%	2.2%
Market-to-book ratio on closing price					2.32
Average number of common shares traded per day (000)	220	266	211	228	231

Note 19 Supplemental Gas and Oil Information (Unaudited)

The Company uses the successful-efforts accounting method for its gas and oil exploration and development activities and for cost-of-service gas and oil properties managed and developed by Wexpro.

Nonregulated Activities

This information pertains to Questar E&P gas and oil activities. Cost-of-service activities are presented in a separate section of this note.

Gas and Oil Exploration and Development Activities

The following information is provided with respect to Questar's gas and oil exploration and development activities, which are located exclusively in the United States. The Company sold its Canadian subsidiary in the fourth quarter of 2002.

Capitalized Costs

The aggregate amounts of costs capitalized for gas and oil exploration and development activities and the related amounts of accumulated depreciation, depletion and amortization are shown below. Future-abandonment costs associated with asset-retirement obligations amounted to $25.0 million and $23.5 million at December 31, 2004 and 2003, respectively. These costs are included in proved properties and support equipment and facilities.

	December 31,	
	2004	2003
	(in thousands)	
Proved properties	$ 1,602,143	$ 1,315,330
Unproved properties	62,678	95,208
Support equipment and facilities	16,932	22,569
	1,681,753	1,433,107

	December 31,	
Accumulated depreciation, depletion and amortization	600,366	501,825
	$ 1,081,387	$ 931,282

Costs Incurred

The costs incurred in gas and oil exploration and development activities are displayed in the table below. The development costs include expenditures to develop a portion of the proved-undeveloped reserves reported at the end of the prior year. These costs were $80.1 million, $55.3 million and $51.1 million in 2004, 2003 and 2002, respectively.

	Year Ended December 31,				
			2002		
	2004 Total	2003 Total	United States	Canada	Total
	(in thousands)				
Property acquisition					
Unproved	$ 13,346	$ 3,779	$ 1,092	$ 119	$ 1,211
Proved	1,205	1,039	45		45
Exploration	25,059	13,521	10,372	627	10,999
Development	238,012	155,226	121,763	3,268	125,031
Asset-retirement obligations	1,699	1,616			
	$ 279,321	$ 175,181	$ 133,272	$ 4,014	$ 137,286

Results of Operations

Following are the results of operations of Questar E&P gas and oil exploration and development activities, before corporate overhead and interest expenses.

	Year Ended December 31,				
			2002		
	2004 Total	2003 Total	United States	Canada	Total
	(in thousands)				
Revenues					
From unaffiliated customers	$ 448,796	$ 343,894	$ 249,239	$ 21,694	$ 270,933
From affiliates			1,172		1,172
Total revenues	448,796	343,894	250,411	21,694	272,105
Production expenses	98,962	77,167	63,149	6,924	70,073
Exploration	9,239	4,498	5,459	627	6,086
Depreciation, depletion and amortization	105,451	88,901	81,473	7,415	88,888
Accretion expense (asset-retirement obligations)	2,001	1,852			
Abandonment and impairment of gas, oil and related properties	12,968	4,151	11,030	153	11,183

	Year Ended December 31,				
Total expenses	228,621	176,569	161,111	15,119	176,230
Revenues less expenses	220,175	167,325	89,300	6,575	95,875
Income taxes Note A	77,502	61,409	27,057	4,228	31,285
Results of operations before corporate overhead, interest and cumulative effect of accounting change	142,673	105,916	62,243	2,347	64,590
Cumulative effect of accounting change for asset retirement obligations		(4,550)			
Results of operations before corporate overhead and interest expenses	$ 142,673	$ 101,366	$ 62,243	$ 2,347	$ 64,590

Note A Income tax expenses have been reduced by nonconventional fuel-tax credits of $4.9 million in 2002. The availability of these credits ended after December 31, 2002.

Estimated Quantities of Proved Gas and Oil Reserves

The table below shows the estimated proved reserves owned by the Company. Estimates of U.S. reserves were prepared by Ryder Scott Company, Netherland, Sewell & Associates, H. J. Gruy and Associates, Inc., and Malkewicz Hueni Associates Inc., independent reservoir engineers. Estimates of Canadian reserves were prepared by Gilbert Laustsen Jung Associates Ltd, and Sproule Associates Limited, independent reservoir engineers. Reserve estimates are based on a complex and highly interpretive process that is subject to continuous revision as additional production and development-drilling information becomes available. The quantities reported below are based on existing economic and operating conditions at December 31. All gas and oil reserves reported were located in the United States and Canada. Canadian properties were sold in the fourth quarter of 2002. The Company does not have any long-term supply contracts with foreign governments or reserves of equity investees.

	Natural Gas			Oil		
	United States	Canada	Total	United States	Canada	Total
		(MMcf)			(Mbbl)	
Balance at January 1, 2002	936,147	61,829	997,976	27,738	3,334	31,072
Revisions of estimates	(108,570)	701	(107,869)	(800)	122	(678)
Extensions and discoveries	240,872	1,712	242,584	2,812	26	2,838
Purchase of reserves in place	42		42			
Sale of reserves in place	(43,220)	(59,433)	(102,653)	(270)	(3,028)	(3,298)
Production	(74,865)	(4,809)	(79,674)	(2,310)	(454)	(2,764)
Balance at December 31, 2002	950,406		950,406	27,170		27,170
Revisions of estimates	14,057		14,057	445		445
Extensions and discoveries	111,575		111,575	1,285		1,285
Purchase of reserves in place	2,098		2,098	8		8
Sale of reserves in place	(152)		(152)	(3)		(3)
Production	(78,811)		(78,811)	(2,324)		(2,324)
Balance at December 31, 2003	999,173		999,173	26,581		26,581
Revisions of estimates	(32,442)		(32,442)	(1,027)		(1,027)
Extensions and discoveries	392,810		392,810	3,964		3,964
Purchase of reserves in place	812		812	5		5
Sale of reserves in place	(21)		(21)			

					Oil	
Production	(89,801)		(89,801)	(2,281)		(2,281)
Balance at December 31, 2004	1,270,531		1,270,531	27,242		27,242
Proved-Developed Reserves						
Balance at January 1, 2002	534,761	53,036	587,797	19,417	2,566	21,983
Balance at December 31, 2002	540,333		540,333	19,942		19,942
Balance at December 31, 2003	612,181		612,181	20,504		20,504
Balance at December 31, 2004	680,587		680,587	21,293		21,293

Standardized Measure of Future Net Cash Flows Relating to Proved Reserves

Future net cash flows were calculated at December 31 using year-end prices and known contract-price changes. The year-end prices do not include any impact of hedging activities. The average year-end price per Mcf of proved natural gas reserves was $5.50 in 2004, $5.57 in 2003 and $3.34 in 2002. The average year-end price per barrel of proved oil and NGL reserves combined was $40.60 in 2004, $30.45 in 2003 and $28.46 in 2002. Year-end production costs, development costs and appropriate statutory income tax rates, with consideration of future tax rates already legislated, were used to compute the future net-cash flows. The statutes allowing income tax credits for nonconventional fuels expired for production after December 31, 2002. All cash flows were discounted at 10% to reflect the time value of cash flows, without regard to the risk of specific properties. The estimated future costs to develop booked proved-undeveloped reserves are $122.5 million, $146.6 million and $128.1 million in 2005, 2006 and 2007, respectively. At the end of this three-year period the Company expects to have evaluated about 61% of the current booked proved-undeveloped reserves.

The assumptions used to derive the standardized measure of future net cash flows are those required by accounting standards and do not necessarily reflect the Company's expectations. The usefulness of the standardized measure of future net cash flows is impaired because of the reliance on reserve estimates and production schedules that are inherently imprecise.

Management considers a number of factors when making investment and operating decisions. They include estimates of probable and proved reserves, and varying price and cost assumptions considered more representative of a range of anticipated economic conditions.

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in thousands)	
Future cash inflows	$ 8,090,022	$ 6,378,076	$ 3,951,706
Future production costs	(1,723,128)	(1,403,893)	(1,049,205)
Future development costs	(663,051)	(338,245)	(326,169)
Future asset-retirement obligations	(104,356)	(96,187)	
Future income tax expenses	(1,854,458)	(1,514,814)	(768,402)
Future net cash flows	3,745,029	3,024,937	1,807,930
10% annual discount to reflect timing of net cash flows	(1,984,491)	(1,494,924)	(908,304)
Standardized measure of discounted future net cash flows	$ 1,760,538	$ 1,530,013	$ 899,626

The principal sources of change in the standardized measure of discounted future net cash flows were.

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in thousands)	
Beginning balance	$ 1,530,013	$ 899,626	$ 604,302

	Year Ended December 31,		
Sales of gas and oil produced, net of production costs	(349,834)	(266,726)	(202,031)
Net changes in prices and production costs	(37,786)	820,131	535,315
Extensions and discoveries, less related costs	763,776	235,891	298,082
Revisions of quantity estimates	(70,767)	33,092	(128,917)
Purchase of reserves in place	1,205	1,039	45
Sale of reserves in place	(1,363)	(8,610)	(126,485)
Change in future development	(123,508)	7,448	(12,128)
Accretion of discount	153,001	89,963	60,430
Net change in income taxes	(28,968)	(345,600)	(138,387)
Change in production rate	(161,734)	21,091	(11,229)
Asset-retirement obligations and other	86,503	42,668	20,629
Net change	230,525	630,387	295,324
Ending balance	$ 1,760,538	$ 1,530,013	$ 899,626

Cost-of-Service Activities

The following information is provided with respect to cost-of-service gas and oil properties managed and developed by Wexpro and regulated by the Wexpro Agreement. Information on the standardized measure of future net cash flows has not been included for cost-of-service activities because the operations of and return on investment for such properties are regulated by the Wexpro Agreement.

Capitalized Costs

Capitalized costs for cost-of-service gas and oil properties net of the related accumulated depreciation and amortization are shown below. Future-abandonment costs associated with asset-retirement obligations amounted to $8.8 million and $8.2 million at December 31, 2004 and 2003, respectively.

	December 31,	
	2004	2003
	(in thousands)	
Wexpro	$ 253,639	$ 233,947
Questar Gas	16,054	17,194
	$ 269,693	$ 251,141

Costs Incurred

Costs incurred by Wexpro for cost-of-service gas and oil-producing activities were $43.6 million, including $0.6 million associated with asset-retirement obligations in 2004, $36.6 million, including $0.3 million associated with asset retirement obligations in 2003 and $26.7 million in 2002.

Results of Operations

Following are the results of operations of the Wexpro's cost-of-service gas and oil-development activities, before corporate overhead and interest expenses.

	Year Ended December 31,		
	2004	2003	2002

	Year Ended December 31,		
		(in thousands)	
Revenues			
From unaffiliated companies	$ 17,315	$ 13,006	$ 8,699
From affiliates Note A	115,637	101,596	94,827
Total revenues	132,952	114,602	103,526
Production expenses	40,613	32,670	23,032
Depreciation and amortization	21,038	20,169	20,475
Accretion expense (asset-retirement obligations)	3,993	183	
Abandonment and impairment of gas and oil properties	2,790		
Total expenses	68,434	53,022	43,507
Revenues less expenses	64,518	61,580	60,019
Income taxes	23,167	22,134	21,572
Results of operations before corporate overhead, interest expenses and cumulative effect of accounting change	41,351	39,446	38,447
Cumulative effect of accounting change for asset-retirement obligations		(563)	
Results of operations before corporate overhead and interest expense	$ 41,351	$ 38,883	$ 38,447

Note A Primarily represents revenues received from Questar Gas pursuant to the Wexpro Agreement.

Estimated Quantities of Cost-of-Service Proved Gas and Oil Reserves

Since the gas reserves operated by Wexpro are delivered to Questar Gas at cost of service, SEC guidelines with respect to standard economic assumptions are not applicable. The SEC anticipated this potential difficulty and provides that companies may give appropriate recognition to differences arising because of the effect of the ratemaking process. Accordingly, Wexpro uses a minimum-producing rate or maximum well-life limit to determine the ultimate quantity of reserves attributable to each well.

The following estimates were made by the Wexpro's reservoir engineers.

	Natural Gas	Oil
	(MMcf)	(Mbbl)
Proved Reserves		
Balance at January 1, 2002	405,681	3,687
Revisions of estimates	(658)	(122)
Extensions and discoveries	56,085	675
Production	(41,208)	(501)
Balance at December 31, 2002	419,900	3,739
Revisions of estimates	24,273	103
Extensions and discoveries	30,286	187
Production	(40,088)	(449)

	Natural Gas	Oil
Balance at December 31, 2003	434,371	3,580
Revisions of estimates	5,624	32
Extensions and discoveries	129,855	1,018
Production	(38,758)	(424)
Balance at December 31, 2004	531,092	4,206
Proved-Developed Reserves		
Balance at January 1, 2002	400,461	3,640
Balance at December 31, 2002	395,821	3,481
Balance at December 31, 2003	406,144	3,330
Balance at December 31, 2004	409,194	3,202

QUESTAR CORPORATION AND SUBSIDIARIES
Schedule of Valuation and Qualifying Accounts

Column A Description	Column B Beginning Balance	Column C Amounts charged to expense	Column D Deductions for accounts written off	Column E Ending Balance
		(in thousands)		
Year Ended December 31, 2004				
Allowance for bad debts	$ 6,694	$ 5,519	$ 6,120	$ 6,093
Year Ended December 31, 2003				
Allowance for bad debts	7,073	3,686	4,065	6,694
Year Ended December 31, 2002				
Allowance for bad debts	6,311	7,886	7,124	7,073

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

The Company has not changed its independent auditors or had any disagreement with them concerning accounting matters and financial statement disclosures within the last 24 months.

ITEM 9A. CONTROLS AND PROCEDURES.

a. Evaluation of Disclosure Controls and Procedures. The Company's Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-14(c) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"). Based on such evaluation, such officers have concluded that, as of the Evaluation Date, the Company's disclosure controls and procedures are effective in alerting them on a timely basis to material information relating to the Company, including its consolidated subsidiaries, required to be included in the Company's reports filed or submitted under the Exchange Act.

b. Changes in Internal Controls. Since the Evaluation Date, there have not been any material changes in the Company's internal controls in other factors that could materially affect such controls.

Management's Assessment of Internal Control Over Financial Reporting

Questar's management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). Questar's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. The criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control Integrated Framework* were used to make this assessment. We believe that the Company's internal control over financial reporting as of December 31, 2004, is effective based on those criteria.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2004, has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included on the next page.

Report of Independent Registered Public Accounting Firm

Shareholders and Board of Directors
Questar Corporation

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

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

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

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

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

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Questar Corporation and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of income, common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004 and our report dated March 3, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Ernst & Young LLP

Salt Lake City, Utah
March 3, 2005

ITEM 9B. OTHER INFORMAITON.

There is no information to report in this section.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

The information requested in this item concerning Questar's directors is presented in the Company's definitive Proxy Statement under the section entitled "Election of Directors" and is incorporated herein by reference. A copy of the definitive Proxy Statement will be filed with the Securities and Exchange Commission on or about April 4, 2005.

Information about the Company's executive officers can be found in Part I. Item 1. *Business*. of this report.

Information concerning compliance with Section 16(a) of the Exchange Act, is presented in the Company's definitive Proxy Statement dated April 4, 2005, under the section entitled "Section 16(a) Compliance" and is incorporated herein by reference.

The Company has a Business Ethics Policy that applies to all of its directors, officers (including its Chief Executive Officer and Chief Financial Officer) and employees. Questar has posted the Business Ethics Policy on its website, www.questar.com. Any waiver of the Business Ethics Policy for executive officers must be approved only by the Company's Board of Directors. Questar will post on its website any amendments to or waivers of the Business Ethics Policy that apply to executive officers.

ITEM 11. EXECUTIVE COMPENSATION.

The information requested in this item is presented in Questar's definitive Proxy Statement for the Company's 2005 annual meeting, under the sections entitled "Executive Compensation" and "Election of Directors" and is incorporated herein by reference. The sections of the Proxy Statement labeled "Committee Report on Executive Compensation" and "Cumulative Total Shareholder Return" are expressly not incorporated into this report.

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

The information requested in this item for certain beneficial owners is presented in Questar's definitive Proxy Statement for the Company's 2005 annual meeting under the section entitled "Security Ownership, Principal Holders" and is incorporated herein by reference. Similar information concerning the securities ownership of directors and executive officers is presented in the definitive Proxy Statement for the Company's 2005 annual meeting under the section entitled "Security Ownership, Directors and Executive Officers" and is incorporated herein by reference.

Finally, information concerning securities authorized for issuance under the Company's equity compensation plans as of December 31, 2004, is presented in the definitive Proxy Statement for the Company's 2005 annual meeting under the section entitled "Equity Compensation Plan Information" and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

The information requested in this item for related transactions involving the Company's directors and executive officers is presented in the definitive Proxy Statement for Questar's 2005 annual meeting under the sections entitled "Information Concerning the Board of Directors" and Certain Relationships "Executive Officers."

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

The information requested in this item for principal accountant fees and services is presented in the definitive Proxy Statement dated April 4, 2005, for Questar's annual meeting under the section entitled "Audit Committee Report" and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

(a) and (c) Financial statements and financial statement schedules filed as part of this report are listed in the index included in Item 8 of this report.

(b) Exhibits. The following is a list of exhibits required to be filed as a part of this report in Item 15(b).

Exhibit No.	Description
2.*	Plan and Agreement of Merger dated as of December 16, 1986, by and among the Company, Questar Systems Corporation, and Universal Resources Corporation. (Exhibit No. (2) to Current Report on Form 8-K dated December 16, 1986.)
3.1.*	Restated Articles of Incorporation as amended effective May 19, 1998. (Exhibit No. 3.1. to Form 10-Q Report for Quarter ended June 30, 1998.)
3.2.*	Bylaws as amended effective August 12, 2003. (Exhibit No. 3. to Form 10-Q Report for Quarter Ended June 30, 2003.)
4.1.*(1)	Rights Agreement dated as of February 13, 1996, between the Company and Chemical Mellon Shareholder Services L.L.C. pertaining to the Company's Shareholder Rights Plan. (Exhibit No. 4. to Current Report on Form 8-K dated February 13, 1996.)
4.2.*	Questar Dividend Reinvestment and Stock Purchase Plan. (Exhibit No. 4. to Current Report on Form 8-K dated February 8, 2000.)
10.1.*	Stipulation and Agreement, dated October 14, 1981, executed by Mountain Fuel; Wexpro; the Utah Department of Business Regulations, Division of Public Utilities; the Utah Committee of Consumer Services; and the staff of the Public Service Commission of Wyoming. (Exhibit No. 10(a) to Mountain Fuel Supply Company's Form 10-K Annual Report for 1981.)
10.2.(2)	Questar Corporation Annual Management Incentive Plan, as amended and restated effective January 1, 2005.
10.3.(2)	Questar Corporation Executive Incentive Retirement Plan, as amended and restated effective January 1, 2005.
10.4.*(2)	Questar Corporation Long-term Stock Incentive Plan, as amended and restated effective March 1, 2001. (Exhibit No. 10.4. to Form 10-K Annual Report for 2000.)
10.5.*(2)	Questar Corporation Executive Severance Compensation Plan, as amended and restated effective February 10, 2004. (Exhibit No. 10.5 to Form 10-K Annual Report for 2003.)
10.6.*(2)	Questar Corporation Deferred Compensation Plan for Directors, as amended and restated effective October 26, 2000. (Exhibit No. 10.6. to Form 10-K Annual Report for 2000.)
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10.9.*(2)	Form of Individual Indemnification Agreement dated February 9, 1993 between Questar

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10.16.*(2)	Employment Agreement between the Company and Charles B. Stanley effective February 1, 2004. (Exhibit No. 10.16 to Form 10-K Annual Report for 2003.)
10.17.*(2)	Consulting Contract between the Questar Regulated Services Company and D. N. Rose effective May 1, 2003. (Exhibit No. 10.1 to Form 10-Q Report for Quarter Ended March 31, 2003.)
10.18.	Questar Corporation Annual Management Incentive Plan II effective January 1, 2005.
10.19.*(2)	Form of Restricted Stock Agreement dated February 8, 2005, for shares granted to officers and key employees. (Exhibit No. 10.1 to Current Report on Form 8-K dated February 8, 2005.)
10.20.*(2)	Form of Restricted Stock Agreement dated February 8, 2005, for shares granted to non-employee directors. (Exhibit No. 10-2 to Current Report on Form 8-K dated February 8, 2005.)
10.21.*(2)	Form of Phantom Stock Agreement dated February 8, 2005, for phantom stock units granted to on-employee directors. (Exhibit No. 10.3 to Current Report on Form 8-K dated February 8, 2005.)
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23.5.	Engineer's Consent
23.6.	Engineer's Consent
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24.	Power of Attorney.
31.1.	Certification signed by Keith O. Rattie, Questar's Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities and Exchange Act of 1934, as amended ("Exchange Act").
31.2.	Certification signed by S. E. Parks, Questar's Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Exchange Act.
32.	Certification signed by Keith O. Rattie and S. E. Parks, Questar's Chief Executive and Chief Financial Officer, respectively, pursuant to Section 906 of the Sarbanes Oxley Act of 2002.
99.1.	Undertakings for Registration Statements on Form S-3 (No. 33-48168) and on Form S-8 (Nos. 33-4436, 33-15149, 33-40800, 33-40801, 33-48169, 333-04913, 333-04951, 333-67658, 333-89486.

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* Exhibits so marked have been filed with the Securities and Exchange Commission as part of the indicated filing and are incorporated herein by reference.

(1) The name of the Rights Agent has been changed to U. S. Bank National Association.

(2) Exhibit so marked is management contract or compensation plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 4th day of March, 2005

QUESTAR CORPORATION
(Registrant)

By: /s/ KEITH O. RATTIE

Keith O. Rattie
Chairman, President and Chief Executive Officer

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

/s/ KEITH O. RATTIE Keith O. Rattie	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ S. E. PARKS S. E. Parks	Senior Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)
* P. S. Baker, Jr.	Director

*	Director
Teresa Beck	
	Director
P. J. Early	
*	Director
L. Richard Flury	
*	Director
J. A. Harmon	
*	Director
Robert E. Kadlec	
*	Director
Robert E. McKee III	
*	Director
Gary G. Michael	
*	Director
Keith O. Rattie	
*	Director
M. W. Scoggins	
*	Director
Harris H. Simmons	
*	Director
C. B. Stanley	

March 4, 2005	* /s/ KEITH O. RATTIE
Date	Keith O. Rattie, Attorney in Fact

EXHIBIT INDEX

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