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

FORM 10-K/A

(MARK ONE)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2001

OR

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

FOR THE TRANSITION PERIOD FROM TO

COMMISSION FILE NUMBER 1-4174

THE WILLIAMS COMPANIES, INC.
(Exact name of registrant as specified in its charter)

DELAWARE (State or other jurisdiction of incorporation or organization)	73-0569878 (I.R.S. Employer Identification No.)
ONE WILLIAMS CENTER, TULSA, OKLAHOMA (Address of principal executive offices)	74172 (Zip Code)

Registrant's telephone number, including area code:
918-573-2000

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

TITLE OF EACH CLASS	NAME OF EACH EXCHANGE ON WHICH REGISTERED
Common Stock, $1.00 par value Preferred Stock Purchase Rights; and Income PACS	New York Stock Exchange and the Pacific Stock Exchange; and New York Stock Exchange

Securities registered Pursuant to Section 12(g) of the Act: NONE

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

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

The aggregate market value of the registrant's voting and non-voting stock held by non-affiliates as of the close of business on February 28, 2002, was approximately $7,972,392,000.

The number of shares of the registrant's common stock held by non-affiliates outstanding at February 28, 2002, was 516,012,427.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Proxy Statement being prepared for the solicitation of proxies in connection with the Annual Meeting of Stockholders of Williams for 2002 are incorporated by reference in Part III.

THE WILLIAMS COMPANIES, INC.

FORM 10-K/A

EXPLANATORY NOTE

We are filing this Amendment No. 1 to Form 10-K in response to comments received from the Securities and Exchange Commission regarding our Annual Report on Form 10-K/A for the fiscal year ended December 31, 2001 that was originally filed on March 7, 2002. This report revises the following disclosures:

- Item 1(c) "Williams Energy Marketing & Energy -- Environmental," page 6, revised to clarify that compliance with various environmental laws and regulations is not expected to have a material adverse effect on capital expenditures, earnings and the competitive position of Williams Energy Marketing & Energy.

- Item 1(c) "Williams Energy Services -- Exploration & Production -- Gas Reserves and Wells," page 17, revised to clarify the disclosure of the filing of Williams' estimates of its total proved net oil and gas reserves with the Department of Energy.

- Item 1(c) "Williams Energy Services -- Exploration & Production -- Operating Reserves," page 18, revised to include the impact of hedging for each year presented and to include a statement that quantifies the amount of the hedging impact per million cubic feet of gas produced for each year presented.

- Item 8 "Supplemental Oil and Gas Disclosures -- Costs Incurred During 2001," page 137, revised to clarify that the costs related to the Barrett acquisition do not include goodwill.

- Item 8 "Supplemental Oil and Gas Disclosures -- Proved Reserves," page 139, amended to remove an incomplete definition of proved oil and gas reserves.

- Item 8 "Supplemental Oil and Gas Disclosures -- Standard Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves," page 139, revised to disclose estimated future development costs for each of the next three years.

- Item 8 "Supplemental Oil and Gas Disclosures -- Standardized Measure of Discounted Future Net Cash Flows," page 140, revised to disclose estimated future development costs separately from estimated future production costs.

This report continues to speak as of the date of the original filing, and we have not updated the disclosure in this report to speak as of a later date. All information contained in this report and the original filing is subject to updating and supplementing as provided in our periodic reports filed with the SEC.

PART I

ITEM 1. BUSINESS

(a) GENERAL DEVELOPMENT OF BUSINESS

The Williams Companies, Inc. (Williams) was incorporated under the laws of the State of Nevada in 1949 and was reincorporated under the laws of the State of Delaware in 1987. The principal executive offices of Williams are located at One Williams Center, Tulsa, Oklahoma 74172 (telephone (918) 573-2000).

On October 6, 1999, a former majority-owned subsidiary of Williams, Williams Communications Group, Inc. (WCG), completed an initial public offering by selling shares of its Class A common stock to the public. In separate private placements, SBC Communications Inc., Intel Corporation and Telefonos de Mexico S.A. de C.V. each purchased a portion of WCG's Class A common stock. On February 26, 2001, Williams and WCG entered into an agreement under which Williams contributed an outstanding promissory note from WCG of approximately $975 million and certain other assets to WCG in exchange for 24,265,892 shares of WCG's Class A common stock. Until the spinoff of WCG on April 23, 2001, Williams owned 100 percent of

WCG's outstanding Class B common stock, which gave Williams approximately 98 percent of the voting power of WCG and approximately 86 percent of the economic interest in WCG.

On March 30, 2001, Williams announced that its board of directors had approved a tax-free distribution of 398,500,000 WCG Class A shares held by Williams to its shareholders of record on April 9, 2001, in the form of a dividend. Immediately prior to the distribution, 100 percent of the shares of WCG's Class B common stock outstanding was converted into shares of Class A common stock. On April 23, 2001, Williams completed the spinoff of WCG to its shareholders, retaining approximately 4.9 percent of the outstanding Class A common stock of WCG.

Also prior to the spinoff of WCG, Williams provided indirect credit support for $1.4 billion of WCG's Note Trust Notes through a commitment to make available proceeds of a Williams equity issuance in the event any one of the following were to occur: (1) a WCG default; (2) downgrading of Williams' senior unsecured debt by any of its credit rating agencies to below investment grade if Williams' common stock closing price is below $30.22 for ten consecutive trading days while such downgrade is in effect; or (3) to the extent proceeds from WCG's refinancing or remarketing of certain structured notes prior to March 2004 produces proceeds of less than $1.4 billion.

On March 5, 2002, Williams received the requisite approvals on its consent solicitation to amend the terms of the WCG Note Trust Notes. The amendment, among other things, eliminates acceleration of the Notes due to a WCG bankruptcy or a Williams credit rating downgrade. The amendment also affirms Williams' obligations for all payments related to the WCG Note Trust Notes, which are due March 2004, and allows Williams to fund such payments from any available sources. With the exception of the March and September 2002 interest payments, totaling $115 million, WCG remains indirectly obligated to reimburse Williams for any payments Williams is required to make in connection with the WCG Note Trust Notes.

On September 13, 2001, Williams purchased the WCG headquarters building and other ancillary assets from WCG for $276 million. Williams then entered into long-term lease arrangements under which WCG is the sole lessee of these assets.

On August 2, 2001, Williams completed its acquisition of Barrett Resources Corporation of Denver, Colorado, following the approval of Barrett stockholders at a special stockholder meeting held August 2, 2001. In the acquisition a wholly owned subsidiary of Williams acquired all of the outstanding shares of Barrett common stock (including the associated preferred stock purchase rights) through a two-step transaction comprised of a cash tender offer for 16,730,502 of the Barrett shares, or approximately 50 percent of the Barrett shares then outstanding, followed by a second step merger in which Barrett was merged with and into a wholly owned subsidiary of Williams. In the merger, each outstanding share, other than shares held by Williams or its subsidiaries, was converted into the right to receive 1.767 shares of Williams' common stock. At the time of the merger, Barrett had total proved reserves of 1.9 trillion cubic feet equivalent and equity production of 350 million cubic feet equivalent per day. The Barrett merger established several new core areas in the Rockies with development drilling programs in the Piceance, Raton and Powder River basins. Other projects exist in the Uinta basin, Wind River basin, Mid-continent area and the Gulf of Mexico.

On August 1, 2001, Kern River Gas Transmission Company filed an application with the Federal Energy Regulatory Commission (FERC) to construct and operate an expansion of its pipeline system that will provide an additional 906,626 dekatherms per day of firm transportation capacity to serve primarily power generation demand in southern Nevada and California. The 2003 Expansion Project will include installing 717 miles of pipeline, three new compressor stations, upgrading, replacing or modifying six existing compressor stations, adding a net total of 163,700 horsepower and upgrading five meter stations. Kern River expects the FERC to issue a certificate by May 1, 2002, and plans to start construction by June 2002. The estimated cost of the expansion is $1.26 billion with a targeted in-service date of May 1, 2003. Kern River's customers will pay for the cost of service of this expansion on an incremental basis.

Williams announced on December 19, 2001, its plans to take several steps to strengthen its balance sheet in order to maintain its investment grade credit rating. The steps of this plan include a $1 billion reduction in 2002 estimated capital spending and the sale of certain non-core assets, the expected proceeds of which total $250 million to $750 million. An additional step of the plan included the sale, which was completed on January 14, 2002, of $1.1 billion of publicly traded units, known as the Income PACS or FELINE PACS, that include a senior debt security and an equity purchase contract. On February 4, 2002, Williams announced that it plans to sell its Midwest petroleum products pipeline and on-system terminals, which sale is in addition to, and more than doubles the cash proceeds from, the balance sheet strengthening plan announced on December 19, 2001. A potential buyer of this pipeline system may be Williams Energy Partners L.P., a subsidiary of Williams.

(b) FINANCIAL INFORMATION ABOUT SEGMENTS

See Part II, Item 8 -- Financial Statements and Supplementary Data.

(c) NARRATIVE DESCRIPTION OF BUSINESS

Williams, through Williams Energy Marketing & Trading Company, Williams Gas Pipeline Company, LLC and Williams Energy Services, LLC, and their respective subsidiaries, engages in the following types of energy-related activities:

- price risk management services and the purchase and sale, and arranging of transportation or transmission, of energy and energy-related commodities including natural gas and gas liquids, crude oil and refined products and electricity;

- transportation and storage of natural gas and related activities through the operation and ownership of five wholly owned interstate natural gas pipelines, several pipeline joint ventures and a wholly owned liquefied natural gas terminal;

- exploration, production and marketing of oil and gas through ownership of 3.2 trillion cubic feet equivalent of proved natural gas reserves primarily located in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States;

- direct investments in international energy projects located primarily in South America and Lithuania, investments in energy and infrastructure development funds in Asia and South America and soda ash mining operations in Colorado;

- natural gas gathering, treating and processing activities through ownership and operation of approximately 11,200 miles of gathering lines, 10 natural gas treating plants and 18 natural gas processing plants (three of which are partially owned) located in the United States and Canada;

- natural gas liquids transportation through ownership and operation of approximately 14,300 miles of natural gas liquids pipeline (4,770 miles of which are partially owned);

- transportation of petroleum products and related terminal services through ownership or operation of approximately 6,747 miles of petroleum products pipeline and 39 petroleum products terminals;

- light hydrocarbon/olefin transportation through 300 miles of pipeline in Southern Louisiana;

- ethylene production through a 5/12 interest in a 1.3 billion pounds per year facility in Geismar, Louisiana;

- production and marketing of ethanol and bio-products through operation and ownership of two ethanol plants (one of which is partially owned) and ownership of minority interests or investments in four other plants;

- refining of petroleum products through operation and ownership of two refineries;

- retail marketing through 61 travel centers;

- petroleum products terminal services through the ownership and operation of five marine terminals and 25 inland terminals that form a distribution network for gasoline and other refined petroleum products throughout the southeastern United States; and

- ammonia transportation and terminal services through ownership and operation of an ammonia pipeline and terminals system that extends for approximately 1,100 miles from Texas and Oklahoma to Minnesota.

Substantially all operations of Williams are conducted through subsidiaries. Williams performs certain management, legal, financial, tax, consultative, administrative and other services for its subsidiaries and at December 31, 2001, employed approximately 1,500 employees at the corporate level to provide these services.

Williams' principal sources of cash are from external financings, dividends and advances from its subsidiaries, investments, payments by subsidiaries for services rendered and interest payments from subsidiaries on cash advances. The amount of dividends available to Williams from subsidiaries largely depends upon each subsidiary's earnings and operating capital requirements. The terms of certain subsidiaries' borrowing arrangements limit the transfer of funds to Williams.

To achieve organizational and operating efficiencies, Williams' energy marketing and trading activities are primarily grouped together under its wholly owned subsidiary, Williams Energy Marketing & Trading Company, its interstate natural gas pipelines and pipeline joint venture investments are grouped together under its wholly owned subsidiary, Williams Gas Pipeline Company, LLC and the other energy operations are primarily grouped together under its wholly owned subsidiary, Williams Energy Services, LLC. Item 1 of this report is formatted to reflect this structure.

WILLIAMS ENERGY MARKETING & TRADING

Williams Energy Marketing & Trading Company, and its subsidiaries, is a national energy services provider that buys, sells and transports a full suite of energy and energy-related commodities, including power, natural gas, refined products, natural gas liquids, crude oil, propane, liquefied natural gas, liquefied petroleum gas and emission credits, primarily on a wholesale level, serving over 652 customers. In addition, Energy Marketing & Trading provides and procures risk management and other energy-related services through a variety of financial instruments and structured transactions including exchange-traded futures, as well as over-the-counter forwards, options, swap, tolling, load serving and full requirements agreements and other derivatives related to various energy and energy-related commodities. See Note 18 of Notes to Consolidated financial statements for information on financial instruments and energy trading activities. At December 31, 2001, Energy Marketing & Trading employed approximately 1,000 employees.

During 2001, Energy Marketing & Trading marketed over 293,808 physical gigawatt hours of power. As part of its approximately 15,000 megawatt power supply portfolio, Energy Marketing & Trading has a mix of owned generation, tolling agreements and supply resources through full requirements transactions in support of its load obligations. Energy Marketing & Trading has entered into a number of long-term agreements at December 31, 2001, to market capacity of electric generation facilities (either existing or to be constructed at various locations throughout the United States) totaling approximately 7,600 megawatts (Alabama -- 846 megawatts; California -- 3,954 megawatts; Louisiana -- 750 megawatts; New Jersey -- 832 megawatts; Pennsylvania -- 700 megawatts; Michigan -- 550 megawatts). Energy Marketing & Trading also has an additional approximately 2,700 megawatts in planned tolling projects to be sited at various locations within the United States. A portion of this supply, for which has been contracted, is in the construction and development stages. On certain contracts, the counterparties have not started construction and are currently negotiating development and environmental permits. Under these tolling arrangements, Energy Marketing & Trading supplies fuel for conversion to electricity and markets capacity, energy and ancillary services related to the generating facilities owned and operated by various counterparties. Approximately 5,400 megawatts of electric generation capacity available through these tolling arrangements located in California, Louisiana and Pennsylvania are operational, with the balance expected to come online by year-end 2002. Energy Marketing & Trading also has entered into several agreements to provide full requirements services for a number of customers whose supply resources are being managed with approximately 2,600 megawatts of load in the United States, including transactions in Indiana, Pennsylvania and Georgia. Additionally, Energy Marketing & Trading has marketing rights for the energy and capacity from three natural gas-fired electric generating plants owned by affiliated companies and located near Bloomfield, New Mexico (60 megawatts); in Hazleton, Pennsylvania (63 megawatts to be expanded to 162 in 2002); and near Worthington, Indiana (170 megawatts). Energy Marketing & Trading's primary power customers include utilities, municipalities, cooperatives, governmental agencies and other power marketers.

Energy Marketing & Trading markets natural gas throughout North America with total physical volumes averaging 3.4 billion cubic feet per day in 2001. Beginning in 2000, Energy Marketing & Trading's natural gas marketing operations focused on activities that facilitate and/or complement the group's power portfolio.

Energy Marketing & Trading's natural gas customers include local distribution companies, utilities, producers, industrials and other gas marketers.

In 2001, Energy Marketing & Trading provided supply, distribution and related risk management services to petroleum producers, refiners and end-users in the United States and various international regions. During 2001, Energy Marketing & Trading's total physical crude oil and petroleum products marketed exceeded 240,600 barrels per day. During 2001, Energy Marketing & Trading also marketed natural gas liquids with total physical volumes averaging 287,200 barrels per day.

Operating Statistics

The following table summarizes marketing and trading volumes for the periods indicated (natural gas volumes for 1999 include sales by the retail gas and electric business, which has now been divested):

	2001	2000	1999
Marketing and trading physical volumes:			
Power (thousand megawatt hours).......................	293,808	141,311	89,810
Natural gas (billion cubic feet per day).............	3.4	3.3	3.6
Refined products, natural gas liquids and crude oil (thousand barrels per day).........................	528	1,009	765

REGULATORY MATTERS

Energy Marketing & Trading's business is subject to a variety of laws and regulations at the local, state and federal levels. At the federal level, important regulatory agencies include the Federal Energy Regulatory Commission (regarding energy commodity transportation and wholesale trading) and the Commodity Futures Trading Commission (regarding various over-the-counter derivative transactions and exemptions and exclusions from the Commodity Exchange Act). Electricity markets, particularly in California, continue to be subject to numerous and wide-ranging regulatory proceedings and investigations, regarding among other things, market structure, behavior of market participants and market prices. Energy Marketing & Trading may be liable for partial refunds as a part of these regulatory actions. Energy Marketing & Trading is also the subject of related state and federal investigations and Civil actions. Each of these matters is discussed in more detail in Note 19 of the Notes to Consolidated Financial Statements.

Management believes that Energy Marketing & Trading's activities are conducted in substantial compliance with the marketing affiliate rules of FERC Order 497. Order 497 imposes certain nondiscrimination, disclosure and separation requirements upon interstate natural gas pipelines with respect to their natural gas trading affiliates. Energy Marketing & Trading has taken steps to ensure it does not share employees or officers with affiliated interstate natural gas pipelines and does not receive information from affiliated interstate natural gas pipelines that is not also available to unaffiliated natural gas trading companies.

COMPETITION

Energy Marketing & Trading's operations directly compete with large independent energy marketers, marketing affiliates of regulated pipelines and utilities and natural gas producers. The financial trading business competes with other energy-based companies offering similar services as well as certain brokerage houses. This level of competition contributes to a business environment of constant pricing and margin pressure.

OWNERSHIP OF PROPERTY

The primary assets of Energy Marketing & Trading are its term contracts, employees, related systems and technological support. In addition, through subsidiaries, Energy Marketing & Trading owns an approximately 170 megawatt gas-fired generating facility located near Worthington, Indiana.

ENVIRONMENTAL

Electricity generation facilities that are subject to tolling or other agreements are subject to various environmental laws and regulations, including laws and regulations regarding emissions. We do not believe compliance with various environmental laws and regulations would have a material adverse effect on capital expenditure, earnings and the competitive position of Williams Energy Marketing & Trading. Facility availability may be affected by these laws and regulations.

WILLIAMS GAS PIPELINE

Williams' interstate natural gas pipeline group, comprised of Williams Gas Pipeline Company, LLC and its subsidiaries (WGP), owns and operates a combined total of approximately 27,500 miles of pipelines with a total annual throughput of approximately 3,800 trillion British Thermal Units of natural gas and peak-day delivery capacity of approximately 17 billion cubic feet of gas. WGP consists of Transcontinental Gas Pipe Line Corporation (Transco), Northwest Pipeline Corporation (Northwest Pipeline), Kern River Gas Transmission Company (Kern River), Texas Gas Transmission Corporation (Texas Gas) and Williams Gas Pipelines Central, Inc. (Central). WGP also holds interests in joint venture interstate and intrastate natural gas pipeline systems.

WGP has combined certain administrative functions, such as information services, technical services and finance, of its operating companies in an effort to lower costs and increase efficiency. Although a single management team manages both Northwest Pipeline and Kern River and a single management team manages both Texas Gas and Central, each of these operating companies operates as a separate legal entity. At December 31, 2001, WGP employed approximately 3,400 employees.

WGP's transmission and storage activities are subject to regulation by the FERC under the Natural Gas Act of 1938 and under the Natural Gas Policy Act of 1978, and, as such, their rates and charges for the transportation of natural gas in interstate commerce, the extension, enlargement or abandonment of jurisdictional facilities and accounting, among other things, are subject to regulation. Each gas pipeline company holds certificates of public convenience and necessity issued by the FERC authorizing ownership and operation of all pipelines, facilities and properties considered jurisdictional for which certificates are required under the Natural Gas Act of 1938. Each gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended by Title I of the Pipeline Safety Act of 1979, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas pipelines.

As a result of Williams' merger with MAPCO Inc. in 1998, Williams acquired an approximate 4.8 percent investment interest in Alliance Pipeline. On December 31, 1999, Williams acquired an additional 9.8 percent interest in Alliance Pipeline. Alliance Pipeline consists of two segments, a Canadian segment and a United States segment. Alliance Pipeline operates an approximate 1,800-mile natural gas pipeline system extending from northeast British Columbia to the Chicago, Illinois area market center, where it interconnects with the North American pipeline grid. On September 17, 1998, the FERC granted a certificate of public convenience and necessity for the United States portion of the Alliance Pipeline system, and on December 3, 1998, the National Energy Board (NEB) of Canada granted a certificate of public convenience and necessity for the Canadian portion. Construction began in the spring of 1999 and the pipeline was placed in service on December 1, 2000. Total cost of the Alliance pipeline system was in excess of $3 billion. At December 31, 2001, Williams' investment in Alliance Pipeline was approximately $185 million.

In February 2001, subsidiaries of Duke Energy and Williams completed their joint acquisition of The Coastal Corporation's 100 percent ownership interest in Gulfstream Natural Gas System, L.L.C., and announced that they are proceeding with the development of the Gulfstream project in lieu of their jointly owned Buccaneer Gas Pipeline Company, L.L.C. gas pipeline project. The Gulfstream project will consist of a new natural gas pipeline system extending from the Mobile Bay area in Alabama to markets in Florida. On February 22, 2001, the FERC issued an order authorizing the construction and operation of the Gulfstream project, and in June 2001 construction commenced on the project. On December 28, 2001, Gulfstream filed an application with the FERC to allow Gulfstream to phase the construction of the approved facilities such that a portion of the project will be placed into service on June 1, 2002 and the remainder on or about June 1, 2003. The estimated capital cost of the project is approximately $1.6 billion, of which Williams' portion is approximately $800 million.

In June 2000, two wholly owned subsidiaries of WGP purchased 100 percent of the partnership interests in Cove Point LNG Limited Partnership (Cove Point). The Cove Point liquefied natural gas (LNG) facility is located in Calvert County, Maryland, and is currently utilized to provide firm peaking services and firm and interruptible transportation services. On January 30, 2001, Cove Point filed an application with the FERC to construct certain new facilities and to reactivate and operate existing facilities and to provide LNG tanker discharging services on a firm and interruptible basis to shippers importing LNG. On October 12, 2001, the FERC issued an order granting Cove Point the authorization to reactivate its existing LNG terminal, to expand the facility, and to construct a fifth storage tank as proposed. Cove Point accepted the certificate on October 18, 2001. On December 19, 2001, the FERC issued an order affirming its October 12 decision. Cove Point proposes to reactivate the LNG import and terminal facilities by the fall of 2002 and to construct and place in service the new LNG storage tank by early 2004. The total estimated cost of the project is approximately $142 million. Cove Point and three shippers have executed 20-year agreements for 100 percent of the 750,000 dekatherms per day of firm LNG discharging services that will be created by the proposed reactivation project.

On April 24, 2001, Georgia Strait Crossing Pipeline LP, a joint venture of WGP and BC Hydro, filed applications with the FERC and the NEB to construct and operate a new pipeline that will provide 95,700 dekatherms per day of firm transportation capacity from Sumas, Washington to Vancouver Island, British Columbia. The Georgia Strait project will include installing 85 miles of pipeline, a 10,302 horse power compression station and two meter stations. Georgia Strait Crossing Pipeline anticipates the FERC to issue a certificate approving the project by July 2002 and the NEB to issue a certificate approving the project by February 2003. Construction is expected to begin in the fall of 2003. The estimated cost of the total Georgia Strait project is approximately $166 million, with WGP's share being 50 percent of such amount. The targeted in-service date is November 2004.

On June 29, 2001, Western Frontier Pipeline Company, LLC, a wholly owned subsidiary of WGP, completed a binding open season for parties interested in subscribing for firm natural gas transportation service on its proposed expansion project. On October 24, 2001, Western Frontier filed an application with the FERC to construct and operate the Western Frontier Pipeline, which will consist of a 400-mile, 30-inch diameter pipeline and 30,000 horsepower of compression designed to transport up to 540,000 dekatherms of natural gas per day from the Cheyenne Hub in northeastern Colorado to Williams' Central pipeline in southwest Kansas and the Oklahoma panhandle. The open season resulted in precedent agreements for 365,000 dekatherms per day of firm transportation service. The project's target in-service date has been delayed one year to November 1, 2004, and work is being done with prospective shippers to further define the market for and scope of this project. The estimated cost of the project is approximately $365 million.

Segment revenues and segment profit for WGP are reported in Note 22 of Notes to Consolidated Financial Statements herein.

A business description of the principal companies in the interstate natural gas pipeline group follows.

TRANSCONTINENTAL GAS PIPE LINE CORPORATION

Transco is an interstate natural gas transportation company that owns and operates a 10,400-mile natural gas pipeline system extending from Texas, Louisiana, Mississippi and the offshore Gulf of Mexico through Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania and New Jersey to the New York City metropolitan area. The system serves customers in Texas and eleven southeast and Atlantic seaboard states, including major metropolitan areas in Georgia, North Carolina, New York, New Jersey and Pennsylvania. Effective May 1, 1995, Transco transferred the operation of certain production area facilities to Williams Field Services Group, Inc., an affiliated company.

Pipeline System and Customers

At December 31, 2001, Transco's system had a mainline delivery capacity of approximately 4.0 billion cubic feet of natural gas per day from its production areas to its primary markets. Using its Leidy Line and market-area storage capacity, Transco can deliver an additional 3.0 billion cubic feet of natural gas per day for a system-wide delivery capacity total of approximately 7.0 billion cubic feet of natural gas per day. Excluding the production area facilities operated by Williams Field Services Group, Inc., an affiliate, Transco's system is composed of approximately 7,200 miles of mainline and branch transmission pipelines, 44 transmission compressor stations and six storage locations. Transmission compression facilities at a sea level-rated capacity total approximately 1.4 million horsepower.

Transco's major natural gas transportation customers are public utilities and municipalities that provide service to residential, commercial, industrial and electric generation end users. Shippers on Transco's system include public utilities, municipalities, intrastate pipelines, direct industrial users, electrical generators, gas marketers and producers. One customer accounted for approximately 11.5 percent of Transco's transportation and storage revenues in 2001. No other customer accounted for more than ten percent of Transco's total revenues in 2001. Transco's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Transco's business. Additionally, Transco offers interruptible transportation and storage services under short-term agreements.

Transco has natural gas storage capacity in five underground storage fields located on or near its pipeline system and/or market areas and operates three of these storage fields. Transco also has storage capacity in a liquefied natural gas (LNG) storage facility and operates the facility. The total top gas storage capacity available to Transco and its customers in such storage fields and LNG facility and through storage service contracts is approximately 216 billion cubic feet of gas. In addition, wholly owned subsidiaries of Transco operate and hold a 35 percent ownership interest in Pine Needle LNG Company, a LNG storage facility with 4 billion cubic feet of storage capacity. Storage capacity permits Transco's customers to inject gas into storage during the summer and off-peak periods for delivery during peak winter demand periods.

Expansion Projects

On May 13, 1998, Transco filed an application with the FERC for approval to construct and operate mainline and Leidy Line facilities (MarketLink) to create an additional 676 million cubic feet per day of firm transportation capacity to serve increased demand in the mid-Atlantic and south Atlantic regions of the United States by a targeted in-service date of November 1, 2000, at an estimated cost of $529 million. On December 17, 1999, the FERC issued an interim order giving Transco conditional approval for MarketLink. Transco filed for rehearing of the interim order and, on April 26, 2000, the FERC issued an order on rehearing that authorized Transco to proceed with the MarketLink project subject to certain conditions. On May 23, 2000, Transco filed a letter with the FERC accepting the MarketLink certificate. On September 20, 2000, Transco filed an application to amend the certificate of public convenience and necessity issued in this proceeding to enable Transco to (a) phase the construction of the MarketLink project to satisfy phased in-service dates requested by the project shippers, and (b) redesign the recourse rate based on the phased construction of the project. On December 13, 2000, the FERC issued an order permitting Transco to construct the MarketLink project in phases as proposed. Phase 1 of the project, which provides approximately 160 million cubic feet per day of additional firm transportation service, was placed into service in December 2001. Phase 2 of the project will consist of 126 million cubic feet per day of additional firm service with an expected in-service date of November 1, 2002. The FERC's December 13, 2000, order required Transco to file executed contracts fully subscribing the remaining capacity of the project (approximately 390 million cubic feet per day) by April 13, 2001. Transco accepted the amended certificate on December 21, 2000. Certain parties filed with the FERC requests for rehearing of the December 13, 2000 order, and on February 12, 2001, the FERC denied the requests. On April 3, 2001, Transco filed a motion requesting that the FERC clarify that Transco could construct Phase 3 of the MarketLink project that consisted of less than all of the remaining certificated MarketLink facilities after the construction of Phases 1 and 2, and that Transco could file by May 1 a report identifying the certificated facilities to be constructed in Phase 3 and a revised project recourse rate. On April 13, 2001, Transco filed firm service agreements with 5 shippers for 205 million cubic feet per day of capacity as required by the December 13, 2000 order approving the phasing of the project. On April 26, 2001, the FERC issued an order denying Transco's pending motion for clarification and stating that Phase 3 of the MarketLink project must consist of all the remaining certificated facilities. The order stated that as of April 13, 2001 the certificate authority to construct additional MarketLink capacity in excess of the 286 million cubic feet per day to be constructed as Phases 1 and 2 expired, but that Transco could file a new application to serve the contracts filed on April 13, 2001. On June 19, 2001, Transco submitted an application for the Leidy East project discussed below, which incorporates a portion of the Phase 3 markets and facilities.

Transco filed an application with the FERC on June 19, 2001, to construct and operate the Leidy East project, which will provide an additional 126 million cubic feet per day of firm natural gas transportation service from Leidy, Pennsylvania to the northeastern United States. Project facilities include approximately 31 miles of pipeline looping and 3,400 horsepower of uprated compression. On October 24, 2001, the FERC issued an order approving the project. Construction is scheduled to begin in March 2002. The proposed in-service date for the project is November 1, 2002. The capital cost of the project is approximately $98 million.

In March 1997, as amended in December 1997, Independence Pipeline Company filed an application with the FERC for approval to construct and operate a new pipeline consisting of approximately 400 miles of 36-inch pipe from ANR Pipeline Company's (ANR) existing compressor station at Defiance, Ohio to Transco's facilities at Leidy, Pennsylvania. The Independence Pipeline project is proposed to provide approximately 916 million cubic feet per day of firm transportation capacity by an anticipated in-service date of November 2002. Independence is owned equally by wholly-owned subsidiaries of Transco, ANR and National Fuel Gas Company. The estimated cost of the project is $678 million, and Transco's equity contributions are estimated to be approximately $68 million based on its expected one-third ownership interest in the project. On December 17, 1999, the FERC gave conditional approval for the Independence Pipeline project, subject to Independence filing long-term, executed contracts with nonaffiliated shippers for at least 35 percent of the capacity of the project. Independence Pipeline filed for rehearing of the interim order. On April 26, 2000, the FERC issued an order denying rehearing and requiring that Independence Pipeline submit by June 26, 2000, agreements with nonaffiliated shippers for at least 35 percent of the capacity of the project. Independence Pipeline met this requirement, and on July 12, 2000, the FERC issued an order granting the necessary certificate authorizations on August 11, 2000 for the Independence Pipeline project. On September 28, 2000, the FERC issued an order denying all requests for rehearing and requests for reconsideration of the Independence certificate order filed by various parties. On November 1, 2001, Independence filed a letter with the FERC requesting an extension of the in service date for the project to November 2004 and an extension of time until November 2003 to submit the final environmental Implementation Plan required by the FERC's order approving the project.

On April 3, 2000, Transco filed an application with the FERC for its Sundance Expansion project, which will create approximately 228 million cubic feet per day of additional firm transportation capacity from Transco's Station 65 in Louisiana to delivery points in Georgia, South Carolina and North Carolina. On March 29, 2001, the FERC issued an order authorizing Transco to construct and operate the project and Transco accepted the order on April 6, 2001. Approximately 38 miles of new pipeline loop along the existing mainline system is being installed along with approximately 33,000 horsepower of new compression and modifications to existing compressor stations in Georgia, South Carolina and North Carolina. The project has a target in-service date of May 2002 and an estimated cost of approximately $134 million.

On September 25, 2001, Transco filed with the FERC an amendment to its certificate application for its Momentum Expansion project to redesign and downsize the project to reflect the termination of two shippers from the project and certain additional capacity subscribed by two other shippers. As amended, the project is proposed to create approximately 347 million cubic feet per day of additional firm transportation capacity on Transco's pipeline system from Station 65 in Louisiana to Station 165 in Virginia. The revised project facilities include approximately 64 miles of pipeline looping and 45,000 horsepower of compression. The revised capital cost of the project is estimated to be approximately $197 million. On February 14, 2002, the FERC issued an order authorizing Transco to construct and operate the project. The project has a targeted in-service date of May 1, 2003.

Transco held an open season in February 2001 for an expansion of the Trenton-Woodbury line, which runs from Transco's mainline at Station 200 in eastern Pennsylvania, around the metropolitan Philadelphia area and southern New Jersey area, to Transco's mainline near Station 205. As a result of the open season, precedent agreements are being negotiated for a total of 49 million cubic feet per day of incremental firm transportation capacity. Transco plans to file for FERC approval of the project in the first quarter of 2002. The target in-service date for the project is November 1, 2003. The project will require approximately 6 miles of looping at a capital cost of approximately $20 million.

Transco completed an open season on July 18, 2001, for the Cornerstone Expansion project, an expansion of Transco's mainline system from Station 65 in Louisiana to Station 165 in Virginia. The project has a target in-service date May 1, 2004. Transco plans to begin the process for seeking FERC approval in the second quarter of 2002. The capital cost of the project will depend on the level of firm market commitment received.

Transco completed an open season on September 7, 2001, for the South Virginia Line Expansion project, a proposed expansion on Transco's pipeline system from Station 165 in Virginia to Hertford County, North Carolina. The project has a target in-service date of May 1, 2005. The capital cost of the project will depend on the level of firm market commitment received.

On July 21, 2000, Cross Bay Pipeline Company, L.L.C. (Cross Bay), a limited liability company formed between subsidiaries of Transco, Duke Energy and KeySpan Energy, filed an application with the FERC for approval of a gas pipeline project which would increase natural gas deliveries into the New York City metropolitan area by replacing and uprating pipeline facilities and installing compression to expand the capacity of Transco's existing Lower New York Bay Extension by approximately 121 million cubic feet per day. On November 8, 2001, the FERC issued an order authorizing the Cross Bay project, subject to certain conditions. On December 5, 2001, the Cross Bay owners elected not to accept the certificate issued by the FERC and decided not to proceed with the Cross Bay project, which resulted in the dissolution of Cross Bay. A wholly owned subsidiary of Transco had a 37.5 percent ownership interest in Cross Bay. Transco's investment in this project was not significant.

On December 1, 2001, Transco transferred certain of its offshore Texas facilities, which assets are not regulated by the FERC, to subsidiaries of Williams Field Services Group, Inc. pursuant to orders granted by the FERC in Docket Nos. CP01-32 and CP01-34. The facilities had a net book value of approximately $3 million.

Operating Statistics

The following table summarizes transportation data for the periods indicated (in trillion British Thermal Units):

	2001	2000	1999
Market-area deliveries:			
Long-haul transportation	766	787	820
Market-area transportation	645	710	623
Total market-area deliveries	1,411	1,497	1,433
Production-area transportation	202	262	222
Total system deliveries	1,613	1,759	1,665
Average Daily Transportation Volumes	4.4	4.8	4.6
Average Daily Firm Reserved Capacity	6.2	6.3	6.3

Transco's facilities are divided into eight rate zones. Five are located in the production area, and three are located in the market area. Long-haul transportation involves gas that Transco receives in one of the production-area zones and delivers in a market-area zone. Market-area transportation involves gas that Transco both receives and delivers within the market-area zones. Production-area transportation involves gas that Transco both receives and delivers within the production-area zones.

NORTHWEST PIPELINE CORPORATION

Northwest Pipeline is an interstate natural gas transportation company that owns and operates a natural gas pipeline system extending from the San Juan Basin in northwestern New Mexico and southwestern Colorado through Colorado, Utah, Wyoming, Idaho, Oregon and Washington to a point on the Canadian border near Sumas, Washington. Northwest Pipeline provides services for markets in California, New Mexico, Colorado, Utah, Nevada, Wyoming, Idaho, Oregon and Washington directly or indirectly through interconnections with other pipelines.

Pipeline System and Customers

At December 31, 2001, Northwest Pipeline's system, having a mainline delivery capacity of approximately 2.9 billion cubic feet of natural gas per day, was composed of approximately 4,100 miles of mainline and branch transmission pipelines and 43 compressor stations having sea level-rated capacity of approximately 343,000 horsepower.

In 2001, Northwest Pipeline transported natural gas for a total of 148 customers. Transportation customers include distribution companies, municipalities, interstate and intrastate pipelines, gas marketers and direct industrial users. The two largest customers of Northwest Pipeline in 2001 accounted for approximately 15.4 percent and 13.7 percent, respectively, of its total operating revenues. No other customer accounted for more than ten percent of total operating revenues in 2001. Northwest Pipeline's firm transportation agreements are generally long-term agreements with various expiration dates and account for the major portion of Northwest Pipeline's business. Additionally, Northwest Pipeline offers interruptible and short-term firm transportation service.

As a part of its transportation services, Northwest Pipeline utilizes underground storage facilities in Utah and Washington enabling it to balance daily receipts and deliveries. Northwest Pipeline also owns and operates a liquefied natural gas storage facility in Washington that provides a needle-peaking service for its system. These storage facilities have an aggregate delivery capacity of approximately 1.3 billion cubic feet of gas per day.

Expansion Projects

On August 29, 2001, Northwest Pipeline filed an application with the FERC to construct and operate an expansion of its pipeline system that will provide an additional 175,000 dekatherms per day of capacity to its transmission system in Wyoming and Idaho in order to reduce reliance on displacement capacity. The Rockies Expansion Project will include installing 91 miles of pipeline loop, upgrades or modifications to five compressor stations for a total increase of 24,924 horsepower. Northwest reached a settlement agreement with the majority of its firm shippers to support roll-in of the expansion costs into its existing rates. Northwest expects the FERC to issue a certificate by September 2002. Northwest plans to start construction by April 2003. The estimated cost of the expansion project is approximately $154 million and the targeted completion date is October 31, 2003.

On October 3, 2001, Northwest Pipeline filed an application with the FERC to construct and operate an expansion of its pipeline system that will provide 276 million cubic feet per day of firm transportation capacity to serve new power generation demand in western Washington. The Evergreen Expansion Project will include installing 28 miles of pipeline loop, upgrading, replacing or modifying five compressor stations and adding a net total of 67,000 horsepower of compression. Northwest expects the FERC to issue a certificate by July 2002 and plans to start construction by August 2002. The estimated cost of the expansion project is approximately $197 million with a targeted in-service date of June 2003. The customers will pay for the cost of service of this expansion on an incremental basis.

On October 3, 2001, Northwest Pipeline filed an application with the FERC to construct and operate an expansion of its pipeline system that will provide an additional 57,000 dekatherms per day of capacity to its transmission system from Stanfield, Oregon to Washougal, Washington. The Columbia Gorge Project will include upgrading, replacing or modifying five existing compressor stations, adding a net total of 24,430 horsepower of compression. The Columbia Gorge Project was filed as part of the Evergreen Expansion Project to reduce reliance on displacement capacity. Northwest reached a settlement with the majority of its firm shippers to support roll-in of 88 percent of the expansion costs with the remainder to be allocated to the Evergreen Project. Northwest expects the FERC to issue a certificate by July 2002 and plans to start construction by April 2003. The estimated cost of the expansion project is approximately $43 million with a targeted in-service date of October 31, 2003.

On May 11, 2001, Northwest Pipeline filed an application with the FERC to construct and operate a lateral pipeline that will provide 161,500 dekatherms per day of firm transportation capacity to serve a new power generation plant. The Grays Harbor Lateral project will include installing 49 miles of 20-inch pipeline, adding 4,700 horsepower at an existing compressor station, and a new meter station. Northwest expects the FERC to issue a certificate by April 15, 2002 and plans to start construction by June 2002. The estimated cost of the lateral project is approximately $75 million with a targeted in-service date of November 2002. The customer will pay for the cost of service of the lateral on an incremental rate basis.

Operating Statistics

The following table summarizes transportation data for the periods indicated (in trillion British Thermal Units):

	2001	2000	1999
Transportation Volumes	734	752	708
Average Daily Transportation Volumes	2.0	2.1	1.9
Average Daily Firm Reserved Capacity	2.7	2.7	2.5

KERN RIVER GAS TRANSMISSION COMPANY

Kern River is an interstate natural gas transportation company that owns and operates a natural gas pipeline system extending from Wyoming through Utah and Nevada to California. Gas transported on the Kern River pipeline is used in enhanced oil recovery operations in the heavy oil fields in California. Gas is also transported to other natural gas consumers in Utah, southern Nevada and southern California for use in the production of electricity, cogeneration of electricity and steam and other applications. The system commenced operations in February 1992.

Pipeline System and Customers

At December 31, 2001, Kern River's system was composed of approximately 926 miles of mainline and branch transmission pipelines and five compressor stations having a mainline designed delivery capacity of approximately 835 million cubic feet of natural gas per day. The pipeline system interconnects with the pipeline facilities of another pipeline company at Daggett, California. From the point of interconnection, Kern River and the other pipeline company have a common 219-mile pipeline, which is owned as tenants in common and is designed to accommodate the combined throughput of both systems. This common facility has a designed delivery capacity of 1.235 billion cubic feet of natural gas per day. Kern River currently has a design capacity of 835 million cubic feet of natural gas per day while the other pipeline has a design capacity of 400 million cubic feet of natural gas per day.

In 2001, Kern River transported natural gas for customers in California, Nevada and Utah. Kern River transported natural gas for use in enhanced oil recovery operations in the heavy oil fields in California and transported to other natural gas consumers in Utah, southern Nevada and southern California for use in the production of electricity, cogeneration of electricity and steam and other applications. At December 31, 2001, Kern River had a total of 29 customers. The three largest customers of Kern River in 2001 accounted for approximately 20.4 percent, 13.3 percent and 11.4 percent, respectively, of its total operating revenues. No other customer accounted for more than ten percent of total operating revenues in 2001. Kern River transports natural gas for customers under firm long-term transportation agreements totaling approximately 835 million cubic feet of natural gas per day and under various interruptible, short-term firm and seasonal firm transportation agreements.

Expansion Projects

On April 6, 2001, Kern River received a FERC certificate to construct and operate an expansion of its pipeline, known as the California Action Project, to provide an additional 114,000 dekatherms per day of limited term transportation capacity from July 1, 2001, through April 30, 2002, and an additional 21,000 dekatherms per day of limited term transportation from July 1, 2001, through April 30, 2003. Temporary facilities will be removed and the permanent facilities will be used as part of the facilities needed to satisfy the 124,500 dekatherms per day of firm transportation contracts initially signed as a part of the Kern River 2002 Expansion Project. The cost of the expansion project was $81.3 million and was placed in service on July 1, 2001. The customers will pay for the cost of service of this expansion on an incremental rate basis.

On July 26, 2001, Kern River received a FERC certificate to construct and operate an expansion of its pipeline, known as the Kern River Amended 2002 Expansion Project, to provide an additional 10,500 dekatherms per day of long-term firm transportation capacity from Wyoming to markets in California. Kern River started construction on October 9, 2001. The project will make permanent the California Action Project facilities which includes the construction of three new compressor stations. An additional compressor at an existing facility in Wyoming will be installed as well as restaging a compressor in Utah and upgrading two-meter stations. The estimated cost of the project excluding the permanent California Action Project facilities is $31.5 million with a targeted in-service date of May 1, 2002. The customers will pay for the cost of the service of this expansion on a rolled-in basis.

On July 18, 2001, Kern River filed an application with the FERC to construct and operate a lateral pipeline that will provide 282,000 dekatherms per day of firm transportation capacity to serve a new power generation plant. The High Desert Lateral will include installing 32 miles of 24-inch pipeline and two meter stations. Kern River expects the FERC to issue a certificate by May 1, 2002, and plans to start construction by June 2002. The estimated cost of the lateral project is approximately $29 million with a targeted in-service date of September 2002. The customer will pay for the cost of the service of the lateral line on an incremental rate basis.

On August 1, 2001, Kern River filed an application with the FERC to construct and operate an expansion of its pipeline system that will serve an additional 902,626 dekatherms per day of firm transportation capacity to serve primarily power generation demand in southern Nevada and California. The 2003 Expansion Project will include installing 717 miles of loop pipeline, three new compressor stations, upgrading, replacing or modifying six existing compressor stations, adding a net total of 163,700 horsepower and upgrading five-meter stations. Kern River expects the FERC to issue a certificate by May 1, 2002, and plans to start construction by June 2002. The estimated cost of the expansion is $1.27 billion with a targeted in-service date of May 1, 2003. The customers will pay for the cost of service of this expansion on an incremental basis.

Operating Statistics

The following table summarizes transportation data for the periods indicated (in trillion British Thermal Units):

	2001	2000	1999
Transportation Volumes	348	312	303
Average Daily Transportation Volumes	1.0	.9	.8
Average Daily Firm Reserved Capacity	.8	.8	.7

TEXAS GAS TRANSMISSION CORPORATION

Texas Gas is an interstate natural gas transportation company that owns and operates a natural gas pipeline system extending from the Louisiana Gulf Coast area and eastern Texas and running generally north and east through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky, Indiana and into Ohio, with smaller diameter lines extending into Illinois. Texas Gas' direct market area encompasses eight states in the South and Midwest, and includes the Memphis, Tennessee; Louisville, Kentucky; Cincinnati and Dayton, Ohio; and Indianapolis, Indiana metropolitan areas. Texas Gas also has indirect market access to the Northeast through interconnections with unaffiliated pipelines.

Pipeline System and Customers

At December 31, 2001, Texas Gas' system, having a mainline delivery capacity of approximately 2.8 billion cubic feet of natural gas per day, was composed of approximately 5,900 miles of mainline, storage and branch transmission pipelines and 31 compressor stations having a sea level-rated capacity totaling approximately 556,000 horsepower.

In 2001, Texas Gas transported natural gas to customers in Louisiana, Arkansas, Mississippi, Tennessee, Kentucky, Indiana, Illinois and Ohio, and indirectly to customers in the Northeast. Texas Gas transported gas for 105 distribution companies and municipalities for resale to residential, commercial and industrial end users. Texas Gas provided transportation services to approximately 15 industrial customers located along its system. At December 31, 2001, Texas Gas had transportation contracts with approximately 560 shippers. Transportation shippers include distribution companies, municipalities, intrastate pipelines, direct industrial users, electrical generators, gas marketers and producers. The largest customer of Texas Gas in 2001 accounted for approximately 13.9 percent of its total operating revenues. No other customer accounted for more than ten percent of total operating revenues in 2001. Texas Gas' firm transportation and storage agreements are generally long-term agreements with various expiration dates and account for the major portion of Texas Gas's business. Additionally, Texas Gas offers interruptible transportation, short-term firm transportation and storage services under agreements that are generally shorter term.

Texas Gas owns and operates gas storage reservoirs in nine underground storage fields located on or near its system or market areas. The storage capacity of Texas Gas' certificated storage fields is approximately 178 billion cubic feet of natural gas. Texas Gas' storage gas is used in part to meet operational balancing needs on its system, to meet the requirements of Texas Gas' firm and interruptible storage customers and to meet the requirements of Texas Gas' No-Notice transportation service, which allows Texas Gas' customers to temporarily draw from Texas Gas' storage gas to be repaid in-kind during the following summer season. A small amount of storage gas is also used to provide Summer No-Notice (SNS) transportation service, designed primarily to meet the needs of summer-season electrical power generation facilities. SNS customers may temporarily draw from Texas Gas' storage gas in the summer, to be repaid during the same summer season. A large portion of the natural gas delivered by Texas Gas to its market area is used for space heating, resulting in substantially higher daily requirements during winter months.

Operating Statistics

The following table summarizes transportation data for the periods indicated (in trillion British Thermal Units):

	2001	2000	1999
Transportation Volumes	709.9	737.8	749.6
Average Daily Transportation Volumes	1.9	2.0	2.1
Average Daily Firm Reserved Capacity	2.1	2.1	2.2

WILLIAMS GAS PIPELINES CENTRAL, INC.

Central is an interstate natural gas transportation company that owns and operates a natural gas pipeline system located in Colorado, Kansas, Missouri, Nebraska, Oklahoma, Texas and Wyoming. The system serves customers in seven states, including major metropolitan areas in Kansas and Missouri, its chief market areas.

Pipeline System and Customers

At December 31, 2001, Central's system, having a mainline delivery capacity of approximately 2.3 billion cubic feet of natural gas per day, was composed of approximately 6,000 miles of mainline and branch transmission and storage pipelines and 43 compressor stations having a sea level-rated capacity totaling approximately 226,000 horsepower.

In 2001, Central transported natural gas to customers in Colorado, Kansas, Missouri, Nebraska, Oklahoma, Texas and Wyoming. At December 31, 2001, Central had transportation contracts with approximately 175 shippers serving approximately 530 cities and towns and 222 industrial customers.

In 2001, approximately 58 percent of Central's total operating revenues were generated from gas transportation services to Central's two largest customers, Kansas Gas Service Company, a division of Oneok, Inc. (approximately 28 percent), and Missouri Gas Energy Company (approximately 30 percent). Kansas Gas Service Company sells or resells gas to residential, commercial and industrial customers principally in certain major metropolitan areas of Kansas. Missouri Gas Energy Company sells or resells gas to residential, commercial and industrial customers principally in certain major metropolitan areas of Missouri. No other customer accounted for more than ten percent of operating revenues in 2001.

Central's firm transportation agreements have various expiration dates ranging from one to 20 years, with the majority expiring in three to eight years. Additionally, Central offers interruptible transportation services under shorter term agreements.

Central operates eight underground storage fields with an aggregate natural gas storage capacity of approximately 43 billion cubic feet and an aggregate delivery capacity of approximately 1.2 billion cubic feet of natural gas per day. Central's customers inject gas into these fields when demand is low and withdraw it to supply their peak requirements. During periods of peak demand, approximately two-thirds of the firm gas delivered to customers is supplied from these storage fields. Storage capacity enables Central's system to operate more uniformly and efficiently during the year.

Operating Statistics

The following table summarizes transportation data for the periods indicated (in trillion British Thermal Units):

	2001	2000	1999
Transportation Volumes	337.6	326.4	324
Average Daily Transportation Volumes	.9	.9	.9
Average Daily Firm Reserved Capacity	2.3	2.2	2.2

REGULATORY MATTERS

Each of the interstate natural gas pipeline companies discussed above has various regulatory proceedings pending. Each company establishes its rates primarily through the FERC's ratemaking process. Key determinants in the ratemaking process are (1) costs of providing service, including depreciation expense, (2) allowed rate of return, including the equity component of the capital structure and related income taxes and (3) volume throughput assumptions. The FERC determines the allowed rate of return in each rate case. Rate design and the allocation of costs between the demand and commodity rates also impact profitability. As a result of these proceedings, the interstate natural gas pipeline companies have collected a portion of their revenues subject to refund. See Note 19 of Notes to Consolidated Financial Statements for the amount accrued for potential refund at December 31, 2001.

Each of the interstate natural gas pipeline companies that were formerly gas supply merchants have undertaken the reformation of its respective gas supply contracts. None of the pipeline companies have any pending supplier take-or-pay, ratable-take or minimum-take claims, which are material to Williams on a consolidated basis. For information on outstanding issues with respect to contract reformation, gas purchase deficiencies and related regulatory issues, see Note 19 of Notes to Consolidated Financial Statements.

COMPETITION

The FERC continues to regulate each of Williams' interstate natural gas pipeline companies pursuant to the Natural Gas Act and the Natural Gas Policy Act of 1978. Competition for natural gas transportation has intensified in recent years due to customer access to other pipelines, rate competitiveness among pipelines, customers' desire to have more than one transporter and regulatory developments. Future utilization of pipeline capacity will depend on competition from other pipelines, use of alternative fuels, the general level of natural gas demand and weather conditions. Electricity and distillate fuel oil are the primary competitive forms of energy for residential and commercial markets. Coal and residual fuel oil compete for industrial and electric generation markets. Nuclear and hydroelectric power and power purchased from electric transmission grid arrangements among electric utilities also compete with gas-fired electric generation in certain markets.

Suppliers of natural gas are able to compete for any gas markets capable of being served by pipelines using nondiscriminatory transportation services provided by the pipeline companies. As the regulated environment has matured, many pipeline companies have faced reduced levels of subscribed capacity as contractual terms expire and customers opt to reduce firm capacity under contract in favor of alternative sources of transmission and related services. This situation, known in the industry as "capacity turnback," is forcing the pipeline companies to evaluate the consequences of major demand reductions in traditional long-term contracts. It could also result in significant shifts in system utilization, and possible realignment of cost structure for remaining customers since all interstate natural gas pipeline companies continue to be authorized to charge maximum rates approved by the FERC on a cost of service basis. WGP does not anticipate any significant financial impact from "capacity turnback". WGP anticipates that it will be able to remarket most future capacity subject to turnback, although competition may cause some of the remarketed capacity to be sold at lower rates or for shorter terms.

Several state jurisdictions have been involved in implementing changes similar to the changes that have occurred at the federal level. States, including New York, New Jersey, Pennsylvania, Maryland, Georgia, Delaware, Virginia, California, Wyoming, Kentucky and Indiana, are currently at various points in the process of unbundling services at local distribution companies. Management expects the implementation of these changes to encourage greater competition in the natural gas marketplace.

OWNERSHIP OF PROPERTY

Each of Williams' interstate natural gas pipeline companies generally owns its facilities in fee, with certain portions, such as certain offshore facilities, being held jointly with third parties. However, a substantial portion of each pipeline company's facilities is constructed and maintained pursuant to rights-of-way, easements, permits, licenses or consents on and across properties owned by others. Compressor stations, with appurtenant facilities, are located in whole or in part either on lands owned or on sites held under leases or permits issued or approved by public authorities. The storage facilities are either owned or contracted under long-term leases or easements.

ENVIRONMENTAL MATTERS

Each interstate natural gas pipeline is subject to the National Environmental Policy Act and federal, state and local laws and regulations relating to environmental quality control. Management believes that, with respect to any capital expenditures and operation and maintenance expenses required to meet applicable environmental standards and regulations, the FERC would grant the requisite rate relief so that the pipeline companies could recover most of the cost of these expenditures in their rates. For this reason, management believes that compliance with applicable environmental requirements by the interstate pipeline companies is not likely to have a material effect upon Williams' earnings or competitive position.

For a discussion of specific environmental issues involving the interstate pipelines, including estimated cleanup costs associated with certain pipeline activities, see "Environmental" under Management's Discussion and Analysis of Financial Condition and Results of Operations and "Environmental Matters" in Note 19 of Notes to Consolidated Financial Statements.

WILLIAMS ENERGY SERVICES

Williams Energy Services, LLC (Williams Energy) is comprised of five major business units: Exploration & Production, International, Midstream Gas & Liquids, Petroleum Services and Williams Energy Partners L.P. Williams Energy, through its subsidiaries, engages in energy exploration and production activities by owning 3.2 trillion cubic feet equivalent of proved natural gas reserves located primarily in New Mexico, Wyoming and Colorado; directly invests in international energy projects located primarily in South America and Lithuania and invests in energy and infrastructure development funds in Asia and Latin America; partially owns a soda ash mining operation in Colorado; and owns or operates approximately 11,200 miles of gathering pipelines (including certain gathering lines owned by Transco but operated by Midstream Gas & Liquids), approximately 14,300 miles of natural gas liquids pipelines (4,770 of which are partially owned), 10 natural gas treating plants, 18 natural gas processing plants (three of which are partially owned) located in the United States and Canada, 69 petroleum products terminals, two ethanol production facilities (one of which is partially owned), two refineries, 89 convenience stores/travel centers, approximately 6,747 miles of petroleum products pipeline and approximately 1,100 miles of ammonia pipeline. At December 31, 2001, Williams Energy, through its subsidiaries, employed approximately 6,870 employees.

Segment revenues and segment profit for Williams Energy's business units are reported in Note 22 of Notes to Consolidated Financial Statements herein.

A business description of each of Williams Energy's business units follows.

EXPLORATION & PRODUCTION

Williams Energy, through its wholly owned subsidiaries Williams Production Company and Williams Production RMT Company in its Exploration & Production unit (E&P), owns and operates producing natural gas leasehold properties in the United States. In addition, E&P is exploring for oil and natural gas.

Acquisitions

On August 2, 2001, Williams Production RMT Company completed its acquisition of Barrett Resources Corporation of Denver, Colorado, through a merger. At the time of the merger, Barrett had total proved reserves of 1.9 trillion cubic feet equivalent and equity productions of 350 million cubic feet equivalent per day. The merger established several new core areas in the Rockies with development drilling programs in the Piceance, Raton and Powder River basins. Other projects exist in the Uinta basin, Wind River basin, Mid-continent area and the Gulf of Mexico.

Oil and Gas Properties

E&P's properties are located primarily in the Rocky Mountains and Gulf Coast areas. Rocky Mountain properties are located in New Mexico, Wyoming and Colorado. Gulf Coast properties are located in Louisiana and east and south Texas.

Gas Reserves and Wells

At December 31, 2001, 2000 and 1999, E&P had proved developed natural gas reserves of 1,599 billion cubic feet equivalent, 603 billion cubic feet equivalent and 548 billion cubic feet equivalent, respectively, and proved undeveloped reserves of 1,579 billion cubic feet equivalent, 599 billion cubic feet equivalent and 504 billion cubic feet equivalent, respectively. Of E&P's total proved reserves, 21 percent are located in the San Juan Basin of Colorado and New Mexico, 26 percent are located in Wyoming and 46 percent are located in Colorado outside of the San Juan Basin. No major discovery or other favorable or adverse event has caused a significant change in estimated gas reserves since year end 2001. E&P has not filed on a recurring basis estimates of its total proved net oil and gas reserves with any U.S. regulatory authority or agency other than the Department of Energy (DOE) and the SEC. The estimates furnished to the DOE have been consistent with those furnished to the SEC, although E&P has not yet filed any information with respect to its estimated total reserves at December 31, 2001 with the DOE. Certain estimates filed with the DOE may not necessarily be directly comparable due to special DOE reporting requirements, such as requirements to report in some instances on a gross, net or total operator basis, and requirements to report in terms of smaller units. The underlying estimated reserves for the DOE did not differ by more than five percent from the underlying estimated reserves utilized in preparing the estimated reserves reported to the SEC.

At December 31, 2001, the gross and net developed leasehold acres owned by E&P totaled 1,025,119 and 515,295, respectively, and the gross and net undeveloped acres owned were 3,852,811 and 2,424,763, respectively. At December 31, 2001, E&P owned interests in 9,846 gross producing wells (4,252 net) on its leasehold lands.

Operating Statistics

The following tables summarize drilling activity for the periods indicated:

2001 WELLS	GROSS	NET
Development		
Drilled	769	347
Completed	767	346
Exploration		
Drilled	14	7
Completed	9	6

COMPLETED DURING	GROSS WELLS	NET WELLS
2001	776	352
2000	246	62
1999	249	48

The majority of E&P's natural gas production is currently being sold to Energy Marketing & Trading at spot market prices. Additionally, E&P has entered into derivative contracts with Energy Marketing & Trading that hedge approximately 79 percent of projected 2002 natural gas production. Energy Marketing & Trading then enters into offsetting derivative contracts with unrelated third parties. Approximately 75 percent of production in 2001 was hedged. The total net production sold during 2001, 2000 and 1999 was 130.7 billion cubic feet equivalent, 65.6 billion cubic feet equivalent and 57.9 billion cubic feet equivalent, respectively. The average production costs including production taxes per million cubic feet of gas produced were $.61, $.57 and $.46, in 2001, 2000 and 1999, respectively. The average wellhead sales price per million cubic feet was $3.13, $2.22 and $1.45, respectively, for the same periods. These sales prices include the impact of hedging contracts, which was a gain of $.46 per million cubic feet for 2001 and losses per million cubic feet of $.74 and $.07 for 2000 and 1999, respectively.

In 1993, E&P conveyed a net profits interest in certain of its properties to the Williams Coal Seam Gas Royalty Trust. Substantially all of the production attributable to the properties conveyed to the Trust was from the Fruitland coal formation and constituted coal seam gas. Williams subsequently sold trust units to the public in an underwritten public offering and retained 3,568,791 trust units representing 36.8 percent of outstanding trust units. During 2000, Williams sold its trust units as part of a Section 29 tax credit transaction, in which Williams retained an option to repurchase the units. Williams registered the units with the SEC and has been repurchasing the units and reselling the units on the open market from time to time. As of February 18, 2002, Williams' option to repurchase totaled 3,308,791 units.

INTERNATIONAL

Williams International Company, through subsidiaries, has made direct investments in energy projects primarily in South America and Lithuania and continues to explore and develop additional projects for international investments. Williams International also has investments in energy and infrastructure development funds in Asia and South America and a soda ash mining operation in Colorado.

El Furrial. Williams International owns a 67 percent interest in a venture near the El Furrial field in eastern Venezuela that constructed, owns and operates medium and high pressure gas compression facilities for Petroleos de Venezuela S.A. (PDVSA), the state owned petroleum corporation of Venezuela.

The medium pressure facility has compression capacity of 130 million cubic feet per day of raw natural gas from 100 to 1,200 p.s.i.g. for delivery into a natural gas processing plant owned by PDVSA. The high pressure facility has compression capacity of 650 million cubic feet per day of processed natural gas from 1,100 to 7,500 p.s.i.g. for injection into PDVSA's El Furrial producing field.

Jose Terminal. Through a long-term operations and maintenance agreement, a consortium, in which Williams International owns 45 percent, operates the PDVSA, Eastern Venezuela crude oil storage and shiploading terminal. Operations began in the second quarter of 1999, and volumes have averaged 500,000 barrels per day. Crude oil exports shipped through this offshore facility are expected to generate approximately 30 percent of Venezuela's forecasted revenues. PDVSA expects to significantly increase the terminal's volume and capacity, currently 800,000 barrels per day, during the next several years.

Pigap II. In April 1999, a consortium in which Williams International owns 70 percent entered into an agreement with PDVSA Petroleo y Gas, S.A., to develop, design, construct, operate, maintain and own a high pressure natural gas injection facility and related infrastructure to take gas, process it and deliver it for injection for secondary recovery of oil from the Santa Barbara/Pirital oil fields located in North Monogas, Venezuela for an initial term of 20 years. Williams International commenced construction in February 2000. Initial operations began in August 2001. The facility is now fully operational. Performance tests have been completed and approved by PDVSA to 75 percent of capacity. The plant is currently being tested at 100 percent of capacity. Maximum capacity is 1.4 billion cubic feet per day.

Accroven. Williams International acquired by purchase from TCPL International Limited and TC International Limited and owns 49.25 percent of Accroven, the Eastern Venezuela project which built, owns and operates two 400 million cubic feet per day natural gas liquids extraction plants, a 50,000 barrel per day natural gas liquids fractionation plant and associated storage and refrigeration facilities for PDVSA. Operations commenced in June 2001. The facility is fully operational with all performance tests completed and approved to 100 percent of capacity.

AB Mazeikiu Nafta. In October 1999 Williams acquired a 33 percent ownership interest and the right to operate AB Mazeikiu Nafta (MN). MN consists of a 320,000 barrel per day refinery, which as of February 28, 2002 was refining 140,000 barrels per day, a 720,000 barrel per day crude oil and refined product pipeline systems within Lithuania and a 160,000 barrel per day crude export facility on the Baltic Sea. Williams took over the operation of these assets in October 1999.

In September of 2000, MN signed an agreement with Yukos Oil Company to transport 80,000 barrels per day through the Butinge terminal. Additionally, MN has entered into multiple short-term supply agreements for the supply of crude oil to the refinery. MN is currently in negotiations with Russian producers for a long-term 80,000-barrel per day refinery supply agreement.

Apco Argentina. Williams International owns approximately a 70 percent interest in Apco Argentina Inc., an oil and gas exploration and production company with operations in Argentina, whose securities are traded on the NASDAQ stock market. Apco Argentina's principal business is its 47.6 percent interest in the Entre Lomas concession in southwest Argentina. It also owns a 45 percent interest in the Canadon Ramirez concession and a 1.5 percent interest in the Acambuco concession.

American Soda L.L.P. -- Sodium Mineral Resource Investment. American Soda L.L.P. is a partnership based in the Piceance Creek Basin of western Colorado for the purpose of engaging in the exploration, development, mining and marketing of soda ash and sodium bicarbonate in an efficient and environmentally responsible manner. This facility has capacities of approximately one million tons of soda ash per year and 150,000 tons of sodium bicarbonate per year. The project is included in International's portfolio because it exports a significant portion of the soda ash production through the United States producer export-marketing consortium, American Natural Soda Ash Company. Soda ash is used in the manufacture of glass, chemicals, paper and detergents. Sodium bicarbonate, more commonly known as baking soda, is used in animal feed, pharmaceutical products, food additives, water treatment, cleaning products and fire extinguishers. As a result of higher than expected construction costs and implementation difficulties, a $170 million impairment charge on the facility was recorded in the fourth-quarter of 2001.

MIDSTREAM GAS & LIQUIDS

Williams Energy, through Williams Field Services Group, Inc. and its subsidiaries, Williams Energy (Canada), Inc. and its subsidiaries, Williams Natural Gas Liquids, Inc. and its subsidiaries and Williams Midstream Natural Gas Liquids, Inc. (collectively Midstream), owns and operates natural gas gathering, processing and treating facilities, and natural gas liquids transportation, fractionation and storage facilities in northwestern New Mexico, southwestern Colorado, southwestern Wyoming, eastern Utah, northwestern Oklahoma, Kansas, northern Missouri, eastern Nebraska, Iowa, southern Minnesota, Tennessee, central Alberta and western British Columbia, Canada and also in areas offshore and onshore in Texas, Alabama, Mississippi and Louisiana. Midstream also operates gathering facilities owned by Transcontinental Gas Pipe Line Corporation, an affiliated interstate natural gas pipeline company, that are currently regulated by the FERC.

Expansion Projects

In 2001, Midstream continued to expand its Gulf Coast operations with the November completion of an onshore gas processing facility and the mid-2002 scheduled completion of deepwater gathering and transportation facilities, each of which is leased by Midstream. Midstream's deepwater expansion efforts continued with agreements to gather and transport oil and natural gas production from Kerr-McGee Corporation's deepwater developments in the Nansen and Boomvang areas in the Western Gulf of Mexico. In order to provide these services to Kerr-McGee and other future prospects, a 137-mile gathering system was constructed to move gas and oil produced by the Nansen and Boomvang prospects. In November 2001, the newly-constructed cryogenic plant located near Markham, Texas was placed into operation. The 300 million cubic feet per day plant processes the gas flows generated from the East Breaks infrastructure. Midstream leases each of these facilities. The lease terms include a five-year base term including the construction phase and can be renewed for another five-year term.

Midstream also signed agreements to provide infrastructure for Dominion Exploration & Production, Inc. and Pioneer Natural Resources Company deepwater projects located in the Devils Tower field in the Gulf of Mexico. Terms of the agreement call for Midstream to construct and own a floating production facility, a 90-mile gas pipeline and a 120-mile oil pipeline to handle production from the Devils Tower field. Midstream intends to use the facilities to provide production-handling services to surrounding fields. The project is scheduled to become operational in June 2003. Midstream's Mobile Bay plant will process the gas and recover NGL's, which will then be transported to the Baton Rouge fractionator via the Tri-States and Wilprise pipelines.

The Redwater Olefins fractionation facility located adjacent to the existing Redwater Fractionation Facility near Edmonton, Alberta, is nearing completion. The new facility is scheduled to be in service in the first quarter 2002 and include feed storage, feed treatment, fractionation, product storage, product treatment and rail loading. The new olefins facility will be an integral part of Midstream's existing McMurray-Redwater System, which involves the recovery of hydrocarbon liquids from the offgas produced at a third party facility near Ft. McMurray, Alberta.

Customers and Operations

Facilities owned and/or operated by Midstream consist of approximately 11,200 miles of gathering pipelines (including certain gathering lines owned by Transco but operated by Midstream), 10 natural gas treating plants, 18 natural gas processing plants (three of which are partially owned), and approximately 14,300 miles of natural gas liquids pipeline, of which approximately 4,770 miles are partially owned. The aggregate daily inlet capacity is approximately 9.0 billion cubic feet for the gathering systems and 12.2 billion cubic feet for the gas processing, treating and dehydration facilities. Midstream's pipeline operations provide customers with one of the nation's largest natural gas liquids transportation systems, while gathering and processing customers have direct access to interstate pipelines, including affiliated pipelines, which provide access to multiple markets.

During 2001, Midstream gathered gas for 255 customers, processed gas for 93 customers and provided transportation to 87 customers. The largest customer accounted for approximately 14 percent of total gathered volumes, and the two largest processing customers accounted for 19 percent and 16 percent, respectively, of processed volumes. The largest transportation customers accounted for 17 percent of transportation volumes. No other customer accounted for more than ten percent of gathered, processed or transported volumes. Williams Canada sold NGLs to 10 customers, three of which individually represent over ten percent of Canadian NGL sales. Midstream's gathering and processing agreements with large customers are generally long-term agreements with various expiration dates. These long-term agreements account for the majority of the gas gathered and processed by Midstream. The natural gas liquids transportation contracts are tariff-based and generally short-term in nature with some long-term contracts for system-connected processing plants. The Canadian NGL sales contracts are typically long-term in nature and are based on cost-of-service or flat fee arrangements.

Acquisitions

Midstream continues to realign its assets to focus on providing producer services in significant growth basins. In order to strengthen its strategic position in the Gulf Coast offshore production areas, Midstream acquired a series of Gulf Coast pipelines in 2001 that included the Black Marlin Pipeline, Green Canyon Gathering System and the Tarpon Transmission System. In January 2002, Midstream announced an asset swap with Duke Energy Field Services that will increase its ownership in the Wyoming area in exchange for its assets in the Hugoton Basin. Terms of the agreement include Midstream receiving Duke's 34 percent ownership interest in the Echo Spring processing plant and related gathering systems near Wamsutter, Wyoming. Midstream currently owns the remaining 66 percent ownership interest in the Wamsutter assets. In exchange, Duke will receive Midstream's Oklahoma Hugoton gathering system, and the Baker, Hobart Ranch and South Bishop gas processing plants located in the Texas and Oklahoma panhandle area. The transaction is expected to close in the first quarter of 2002.

In January 2002, Midstream sold various gas gathering and processing assets located in south Texas. These assets included a sour gas treatment plant and gathering lines near Tilden, an inactive gas processing plant in Bee County and Midstream's 76 percent interest in the Webb Duval gathering system. In addition, the sale of 492 miles of Transco transmission lines in far southern Texas is expected to close in the third quarter of 2002.

Operating Statistics

The following table summarizes gathering, processing, natural gas liquid sales and transportation volumes for the periods indicated. The information includes operations attributed to facilities owned by Transco but operated by Midstream.

	2001	2000	1999
Gas volumes:			
Domestic gathering (trillion British Thermal Units)	2,174	2,116	2,085
Domestic processing (trillion British Thermal Units)	563	561	539
Domestic natural gas liquids sales (millions of gallons)	980	1,151	838
Domestic natural gas liquids transportation (millions of barrels)	303	291	282
Canadian gas liquids sales (millions of gallons)	1,391	368*	--

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* Partial year (acquired October 11, 2000)

PETROLEUM SERVICES

Williams Energy, through wholly owned subsidiaries in its Petroleum Services unit, owns and operates a petroleum products pipeline system, an ethylene plant and olefin pipeline, 39 petroleum products terminals (some of which are partially owned), two ethanol production plants (one of which is majority owned), two refineries and 89 convenience stores/travel centers, and provides services and markets products related thereto. In 2001, no one customer accounted for ten percent of Petroleum Services' total revenues.

Transportation

A subsidiary in the Petroleum Services unit, Williams Pipe Line Company, owns and operates a petroleum products pipeline system that covers an 11-state area extending from Oklahoma to North Dakota, Minnesota and Illinois. The system is operated as a common carrier offering transportation and terminalling services on a nondiscriminatory basis under published tariffs. The system transports refined products and liquified petroleum gases. On February 4, 2002, Williams announced that it plans to sell this pipeline system and its on-system terminals. Williams Energy Partners L.P. is a potential purchaser of this pipeline system.

At December 31, 2001 the system includes approximately 6,747 miles of pipeline in various sizes up to 16 inches in diameter. The system includes 77 pumping stations, 26.5 million barrels of storage capacity and 39 delivery terminals. The terminals are equipped to deliver refined products into tank trucks and tank rail cars. The maximum number of barrels that the system can transport per day depends upon the operating balance achieved at a given time between various segments of the system. Because the balance is dependent upon the mix of products to be shipped and the demand levels at the various delivery points, the exact capacity of the system cannot be stated. In 2001, total system shipments averaged 647,000 barrels per day.

The operating statistics set forth below relate to the system's operations for the periods indicated:

	2001	2000	1999
Shipments (thousands of barrels):			
Refined products:			
Gasolines	137,552	130,580	132,444
Distillates	75,887	74,299	70,466
Aviation fuels	14,752	16,488	12,060
LP-Gases	7,901	7,781	7,521
Total Shipments	236,092	229,148	222,491
Daily average (thousands of barrels)	647	626	610
Barrel miles (millions)	70,466	68,211	67,768

Williams and its subsidiary, Longhorn Enterprises of Texas, Inc. (LETI), own a total 32.1 percent interest in Longhorn Partners Pipeline, LP, a joint venture formed to construct and operate a refined products pipeline from Houston, Texas, to El Paso, Texas. Pipeline construction is substantially complete pending regulatory and environmental approvals, and operations are expected to commence after receiving such approvals in mid-2002. Williams Pipe Line has designed and constructed and will operate the pipeline, and Williams Pipe Line and LETI have contributed a total of approximately $105 million and loaned approximately $32 million to the joint venture.

On June 30, 2000, a subsidiary in the Petroleum Services unit purchased an interest in the Trans-Alaska Pipeline System from Mobil Alaska Pipeline Company for $32.5 million. Petroleum Services' interest consists of 3.0845 percent of the pipeline and the Valdez crude terminal. Petroleum Services' share of the crude oil deliveries for 2001 was approximately 14.0 million barrels.

Olefins

Petroleum Services owns and operates an approximate 42 percent interest in a 1.3 billion pounds per year ethylene plant near Geismar, Louisiana. Williams Energy Marketing & Trading provides feedstocks to the olefins facility and markets the Williams share of the ethylene produced from the facility through a tolling arrangement with Petroleum Services. The olefins facility is supported by pipeline and storage assets owned by Williams Midstream Gas & Liquids. Midstream owns and operates a 215-mile light hydrocarbon transportation system and operates and has partial ownership in an 85-mile olefin pipeline and storage network, which connects, either directly or indirectly, most major natural gas liquids producers and olefin consumers in Louisiana.

Feedstock processed and ethylene produced by the olefin facility, which was acquired in March 1999, noted below represents Williams approximate 42 percent interest:

	2001	2000	1999
Feedstock processed (thousands of pounds):..............	477,106	793,316	596,512
Ethylene production (thousands of pounds):..............	315,113	520,758	386,998

Bio-Energy

Williams Bio-Energy, LLC, is engaged in the production and marketing of ethanol. Williams Bio-Energy owns and operates two ethanol plants (one of which is partially owned) for which corn is the principal feedstock. The Pekin, Illinois, plant has an annual production capacity of 100 million gallons of fuel-grade and industrial ethanol and also produces various coproducts and bio-products. Bio-products, mainly flavor enhancers, produced at the Pekin plant are marketed primarily to food processing companies. The Aurora, Nebraska, plant (in which Williams Bio-Energy owns an approximate 77 percent interest) has an annual production capacity of 30 million gallons. In late 2000, Williams Bio-Energy acquired a minority interest in two affiliate plants in South Dakota and made equity investments in two other plants in Minnesota and Iowa totaling approximately 40 million gallons of annual ethanol production capacity produced primarily from corn. In addition, Williams Bio-Energy obtained marketing rights to 100 percent of the ethanol output of the four plants. Williams Bio-Energy also markets ethanol produced by third parties. In 2001, Williams Bio-Energy entered into marketing agreements to market all of the ethanol produced by Heartland Grain Fuels, L.P., Minnesota Energy, Sunrise Energy and Tri-State Ethanol Company, LLC.

The sales volumes set forth below include ethanol produced by third parties as well as by Williams Bio-Energy for the periods indicated:

	2001	2000	1999
Ethanol sold (thousands of gallons).....................	265,854	227,458	200,077

Refining

Petroleum Services, through subsidiaries in its unit, owns and operates two petroleum products refineries: the North Pole, Alaska refinery and the Memphis, Tennessee refinery. The financial results of the North Pole refinery and the Memphis refinery may be significantly impacted by changes in market prices for crude oil and refined products. Petroleum Services cannot predict the future of crude oil and product prices or their impact on its financial results.

The North Pole Refinery includes the refinery located at North Pole, Alaska and a terminal facility at Anchorage, Alaska. The refinery, the largest in the state, is located approximately two miles from its supply point for crude oil, the Trans-Alaska Pipeline System (TAPS). The refinery's processing capability is approximately 215,000 barrels per day. At maximum crude throughput, the refinery can produce up to 70,000 barrels per day of retained refined products. These products are jet fuel, gasoline, diesel fuel, heating oil, fuel oil, naphtha and asphalt. These products are marketed in Alaska, Western Canada and the Pacific Rim principally to wholesale, commercial, industrial and government customers and to Petroleum Services' retail petroleum group.

Barrels processed and transferred by the North Pole Refinery per day are noted below:

	2001	2000	1999
Barrels Processed and Sold (barrels)....................	65,089	58,109	56,395

The North Pole Refinery's crude oil is purchased from the state of Alaska or is purchased or received on exchanges from crude oil producers. The refinery has two long-term agreements with the state of Alaska for the purchase of royalty oil, both of which are scheduled to expire on December 31, 2003. The agreements provide for the purchase of up to 56,000 barrels per day (approximately 80 percent of the refinery's supply needs for retained production) of the state's royalty share of crude oil produced from Prudhoe Bay, Alaska. These volumes, along with crude oil either purchased or received under exchange agreements from crude oil producers or other short-term supply agreements with the state of Alaska, are utilized as throughput for the refinery. Approximately 30 percent of the throughput is refined, retained and sold as finished product and the remainder of the throughput is returned to the TAPS and either delivered to repay exchange obligations or sold.

The Memphis Refinery, which includes three petroleum products terminals, is the only refinery in the state of Tennessee and has a throughput capacity of approximately 175,000 barrels per day. Petroleum Services commissioned a 36,000 barrel per day continuous catalyst regeneration reformer in May 2000. The reformer enables the refinery to produce in greater volumes premium gasoline to be delivered in the mid-South region of the United States.

The Memphis Refinery produces gasoline, low sulfur diesel fuel, jet fuel, K-1 kerosene, refinery-grade propylene, No. 6 fuel oil, propane and elemental sulfur. In 2001, these products were exchanged or marketed primarily in the Mid-South region of the United States to wholesale customers, such as industrial and commercial consumers, jobbers, independent dealers and other refiner/marketers. Through January 2001, Williams' Energy Marketing & Trading unit marketed the refinery's products. Petroleum Services began marketing the refinery's products directly in February 2001.

The Memphis Refinery has access to crude oil from the Gulf Coast via common carrier pipeline and by river barges. In addition to domestic crude oil, the Memphis Refinery receives and processes certain foreign crudes. The Memphis Refinery's purchase contracts are generally short-term agreements.

Average daily barrels processed and transferred by the Memphis Refinery are noted below:

	2001	2000	1999
Barrels Processed and Sold (barrels)....................	175,914	161,751	133,494

Retail Petroleum

Petroleum Services, primarily under the brand names "Williams TravelCenters" and "Williams Express," is engaged in the retail marketing of gasoline, diesel fuel, other petroleum products, convenience merchandise and restaurant and fast food items. On May 31, 2001, Petroleum Services sold 198 MAPCO Express convenience stores to Delek -- The Israel Fuel Corporation Limited. At December 31, 2001, the retail petroleum group operated 61 interstate TravelCenter locations and 28 Williams Express convenience stores in Alaska. The TravelCenter sites consist of 35 modern facilities providing gasoline and diesel fuel, merchandise and restaurant offerings for both traveling consumers and professional drivers, and 15 locations providing fuel and merchandise. The convenience store sites are primarily concentrated in the vicinities of Nashville and Memphis, Tennessee and Anchorage and Fairbanks, Alaska. All of the motor fuel sold by Williams TravelCenters and convenience stores is supplied either by exchanges, directly from either the Memphis or North Pole Refineries or through Williams Energy Marketing & Trading.

Convenience merchandise, restaurants and fast food accounted for approximately 60 percent of the retail petroleum group's gross margins in 2001. Gasoline and diesel sales volumes for the periods indicated are noted below:

	2001	2000	1999
Gasoline (thousands of gallons).........................	254,762	340,724	339,470
Diesel (thousands of gallons)...........................	574,039	434,655	264,248

WILLIAMS ENERGY PARTNERS L.P.

In October 2000, Williams formed Williams Energy Partners L.P. (WEP), a wholly owned partnership, to acquire, own and operate a diversified portfolio of energy assets, concentrated around the storage, transportation and distribution of refined petroleum products and ammonia. On October 30, 2000, WEP filed with the Securities and Exchange Commission a registration statement on Form S-1 related to an initial public offering of common units. In February 2001, 4,600,000 common units, representing approximately 40 percent of the total outstanding units, were sold to the public. Williams currently owns approximately 60 percent of the partnership including its general partner interest. WEP's common units trade on the New York Stock Exchange under the symbol WEG.

WEP's asset portfolio includes five marine petroleum product terminal facilities with an aggregate storage capacity of approximately 18 million barrels, 25 inland terminals with an aggregate storage capacity of 4.7 million barrels and an ammonia pipeline and terminals system that extends for approximately 1,100 miles from Texas and Oklahoma to Minnesota. Williams Energy Marketing & Trading is WEP's largest terminal customer accounting for approximately 9.5 percent of WEP's terminal revenues for 2001.

REGULATORY MATTERS

International. AB Mazeikiu Nafta is regulated by the Government of the Republic of Lithuania. The four primary ministries that interact on the day to day activities of MN are the Ministry of Economy, the Ministry of Transportation, the Ministry of Environment and the Ministry of Finance. These Ministries provide governmental regulations regarding the operation of the refinery, transportation of crude oil and refined products through the pipeline and terminal system, and financial reporting of MN. In addition the Ministry of Economy controls MN's Board of Directors and Supervisory Council.

Midstream. In May 1994, after reviewing its legal authority in a Public Comment Proceeding, the FERC determined that while it retains some regulatory jurisdiction over gathering and processing performed by interstate pipelines, pipeline-affiliated gathering and processing companies are outside its authority under the Natural Gas Act. An appellate court has affirmed the FERC's determination, and the United States Supreme Court has denied requests for certiorari. As a result of these FERC decisions, some of the individual states in which Midstream conducts its operations have considered whether to impose regulatory requirements on gathering companies. Kansas, Oklahoma and Texas currently regulate gathering activities using complaint mechanisms under which the state commission may resolve disputes involving an individual gathering arrangement. Other states may also consider whether to impose regulatory requirements on gathering companies.

In February 1996, Midstream and Transco filed applications with the FERC to spindown all of Transco's gathering facilities to Midstream. The FERC subsequently denied the request in September 1996. Midstream and Transco sought rehearing in October 1996. In August 1997, Midstream and Transco filed a second request for expedited treatment of the rehearing request. The FERC denied rehearing on June 14, 2001. On July 26, 2001, Midstream and Transco filed an appeal of the orders with the Circuit Court of Appeals for the District of Columbia. In February 1998, Midstream and Transco filed separate applications to spindown an onshore gathering system located in Texas, the Tilden/McMullen gathering system, which was also one of the subjects of the pending rehearing request. In May 1999, the FERC approved the spindown application only for the facilities upstream of the Tilden treating plant. The transfer of ownership of these facilities occurred in April 2000. As a result of a court appeal reversing and remanding the FERC's decision that the offshore system of Sea Robin pipeline were transmission facilities regulated by FERC under the Natural Gas Act, in June 1999, the FERC issued an order in the Sea Robin remand proceeding finding that the upstream portions of the Sea Robin system are nonjurisdictional gathering but the downstream portion is regulated transmission. In July 2000, the FERC affirmed that determination and denied rehearing requests. Appeals are pending in the District of Columbia Circuit Court of Appeals. In April 2000, the FERC issued "Regulations under the Outer Continental Shelf Lands Act Governing the Movement of Natural Gas on Facilities on the Outer Continental Shelf," which require most non-interstate natural gas pipelines located on the Outer Continental Shelf to post prices, terms and conditions of service. Williams and other parties appealed the Rule, challenging FERC's authority to issue it. On January 11, 2002, the United States District Court for the District of Columbia granted William's motion for summary judgment and permanently enjoined the FERC from enforcing that rule. In November 2000, Midstream and Transco filed applications with the FERC to spindown two of Transco's offshore gathering facilities to Midstream (the North Padre system and the Central Texas system). Transco and Midstream explained that it was the first in a series of spindown filings designed to be consistent with the current policy under the Sea Robin reformulated test. Subsequently, Midstream and Transco filed to spindown the North High Island/West Cameron system and the Central Louisiana system. This series of spindown filings will generally request the spindown of smaller systems than originally proposed in the 1996 filings, but Transco and Midstream have stated that they reserve their rights to continue pursuit of the original spindown proposals. The FERC granted the proposed spindown of the North Padre Island system and the Central Texas system on July 25, 2001. A rehearing order was issued on December 19, 2001, which maintained the July 25th order's determination on the function of the facilities, but did not require Transco to change its rates before the transfer of facilities. The FERC granted only part of the proposed spindowns for the North High Island/West Cameron system on July 25, 2001 and on the Central Louisiana system on August 31, 2001. On December 19, 2001, the FERC issued orders on rehearing in both proceedings, maintaining its previous determination that only some of the proposed facilities function as non-jurisdictional gathering. On January 7, 2002 Midstream filed an appeal of each of the orders, the North High Island/West Cameron order and the Central Louisiana order, with the Circuit Court of Appeals for the District of Columbia. On January 9, 2002, Midstream and Transco moved to consolidate those two appeals with the pending appeal of the comprehensive spindown that had been filed July 26, 2001.

Midstream's natural gas liquids group is subject to various federal, state, and local environmental and safety laws and regulations. Midstream's pipeline operations are subject to the provisions of the Hazardous Liquid Pipeline Safety Act. In addition, the tariff rates, shipping regulations, and other practices of the Mid-America, Rio Grande, Seminole, Wilprise and Tri-States pipelines are regulated by the FERC pursuant to the provisions of the Interstate Commerce Act applicable to interstate common carrier petroleum and petroleum products pipelines. Both of these statutes require the filing of reasonable and nondiscriminatory tariff rates and subject Midstream to certain other regulations concerning its terms and conditions of service. The Mid-America, Rio Grande, Seminole, Wilprise and Tri-States pipelines also file tariff rates covering intrastate movements with various state commissions. The United States Department of Transportation has prescribed safety regulations for common carrier pipelines. The pipeline systems are subject to various state laws and regulations concerning safety standards, exercise of eminent domain, and similar matters.

Midstream's Canadian natural gas group's assets, except for the Taylor to Boundary Lake Pipeline, are regulated provincially. The Alberta-based assets are regulated by the Alberta Energy & Utilities Board (AEUB) and Alberta Environment, while the British Columbia-based assets are regulated by B.C. Oil and Gas Commission and the British Columbia Ministry of Environment, Lands and Parks. The regulatory system for Alberta oil and gas industry incorporates a large measure of self-regulation, meaning that licensed operators are held responsible for ensuring that their operations are conducted in accordance with all provincial regulatory requirements. For situations in which non-compliance with the applicable regulations is at issue, the AEUB and Alberta Environment have implemented an enforcement process with escalating consequences. The British Columbia Oil and Gas Commission operates in a slightly different manner than the AEUB, with more emphasis placed on pre-construction criteria and the submission of post-construction documentation, as well as periodic inspections. Only one asset is subject to federal regulation, under the jurisdiction of the NEB. The Taylor to Boundary Lake Pipeline, which is Leg Number 2 of the NGL Gathering System, is regulated by the National Energy Board as a Group 2 inter-provincial pipeline between B.C. and Alberta. While Group 2 regulated companies are required to post a toll and tariff for the facilities they operate, they are regulated on a "complaint only" basis and need only to employ standard uniform accounting procedures, rather than the more onerous Group 1 NEB-mandated accounting and reporting requirements.

Petroleum Services. Williams Pipe Line, as an interstate common carrier pipeline, is subject to the provisions and regulations of the Interstate Commerce Act. Under this Act, Williams Pipe Line is required, among other things, to establish just, reasonable and nondiscriminatory rates, to file its tariffs with the FERC, to keep its records and accounts pursuant to the Uniform System of Accounts for Oil Pipeline Companies, to make annual reports to the FERC and to submit to examination of its records by the audit staff of the FERC. Authority to regulate rates, shipping rules and other practices and to prescribe depreciation rates for common carrier pipelines is exercised by the FERC. The Department of Transportation, as authorized by the 1995 Pipeline Safety Reauthorization Act, is the oversight authority for interstate liquids pipelines. Williams Pipe Line is also subject to the provisions of various state laws applicable to intrastate pipelines.

Environmental regulations and changing crude oil supply patterns continue to affect the refining industry. The industry's response to environmental regulations and changing supply patterns will directly affect volumes and products shipped on the Williams Pipe Line system. Environmental Protection Agency regulations, driven by the Clean Air Act, require refiners to change the composition of fuel manufactured. A pipeline's ability to respond to the effects of regulation and changing supply patterns will determine its ability to maintain and capture new market shares. Williams Pipe Line has successfully responded to changes in diesel fuel composition and product supply and has adapted to new gasoline additive requirements. Reformulated gasoline regulations have not yet significantly affected Williams Pipe Line. Williams Pipe Line will continue to attempt to position itself to respond to changing regulations and supply patterns but cannot predict how future changes in the marketplace will affect its market areas.

Williams Energy Partners L.P. The Surface Transportation Board, a part of the United States Department of Transportation, has jurisdiction over interstate pipeline transportation of ammonia. Ammonia transportation rates must be reasonable, and a pipeline carrier may not unreasonably discriminate among its shippers. In determining a reasonable rate, the Surface Transportation Board will consider, among other factors, the effect of the rate on the volumes transported by that carrier, the carrier's revenue needs and the availability of other economic transportation alternatives. Because in some instances WEP transports ammonia between two terminals in the same state, its pipeline operations are subject to regulation by the state regulatory authorities in Iowa, Nebraska, Oklahoma and Texas.

COMPETITION

Exploration & Production. Williams Energy's E&P unit competes with a wide variety of independent producers as well as integrated oil and gas companies for markets for its production. E&P has three general phases of operations: acquiring oil and gas properties, developing non-producing properties and operating producing properties. In the process of acquiring minerals, the primary methods of competition are on acquisition price and terms such as duration of the mineral lease, the amount of the royalty payment and special conditions related to rights to use the surface of the land under which the mineral interest lies. In the process of developing non-producing properties, E&P does not face significant competition. In the operating phase, the primary method of competition involves operating efficiencies related to the cost to produce the hydrocarbons from the reservoir. The majority of Williams Energy's ownership interests in exploration and production properties are held as working interests in oil and gas leaseholds.

Midstream. Williams Energy competes for gathering and processing business with interstate and intrastate pipelines, producers and independent gatherers and processors. Numerous factors impact any given customer's choice of a gathering or processing services provider, including rate, location, term, timeliness of well connections, pressure obligations and the willingness of the provider to process for either a fee or for liquids taken in-kind. Competition for the natural gas liquids pipelines include other pipelines, tank cars, trucks, barges, local sources of supply (refineries, gasoline plants and ammonia plants) and other sources of energy such as natural gas, coal, oil and electricity. Factors that influence customer transportation decisions include rate, location, nature of service and timeliness of delivery.

Petroleum Services. Williams Pipe Line operates without the protection of a federal certificate of public convenience and necessity that might preclude other entrants from providing like service in its area of operations. Further, Williams Pipe Line must plan, operate and compete without the operating stability inherent in a broad base of contractually obligated or owner-controlled usage. Because Williams Pipe Line is a common carrier, its shippers need only meet the requirements set forth in its published tariffs in order to avail themselves of the transportation services offered by Williams Pipe Line.

Competition exists from other pipelines, refineries, barge traffic, railroads and tank trucks. Competition is affected by trades of products or crude oil between refineries that have access to the system and by trades among brokers, traders and others who control products. These trades can result in the diversion from the Williams Pipe Line system of volume that might otherwise be transported on the system. Shorter, lower revenue hauls may also result from these trades. Williams Pipe Line also is exposed to interfuel competition whereby an energy form shipped by a liquids pipeline, such as heating fuel, is replaced by a form not transported by a liquids pipeline, such as electricity or natural gas. While Williams Pipe Line faces competition from a variety of sources throughout its marketing areas, the principal competition is other pipelines. A number of pipeline systems, competing on a broad range of price and service levels, provide transportation service to various areas served by the system. The possible construction of additional competing products or crude oil pipelines, conversions of crude oil or natural gas pipelines to products transportation, changes in refining capacity, refinery closings, changes in the availability of crude oil to refineries located in its marketing area or conservation and conversion efforts by fuel consumers may adversely affect the volumes available for transportation by Williams Pipe Line.

Williams Bio-Energy's fuel ethanol operations compete in local, regional and national fuel additive markets with other ethanol products and other fuel additive producers, such as refineries and methyl tertiary butyl ether (MTBE) producers. MTBE has been banned in California effective January 1, 2003, and in other states due to ground water contamination problems. Williams Bio-Energy's other products compete in global markets against a variety of competitors and substitute products.

The principal competitive forces affecting Williams Energy's refining businesses are feedstock costs, refinery efficiency, refinery product mix and product distribution. Some of Memphis Refinery's competitors can process sour crude, and accordingly, are more flexible in the crudes that they can process. Williams Energy has limited crude oil reserves and does not engage in crude oil exploration, and it must therefore obtain its crude oil requirements from unaffiliated sources. Williams Energy believes that it will be able to obtain adequate crude oil and other feedstocks at generally competitive prices for the foreseeable future.

The principal competitive factors affecting Williams Energy's retail petroleum business are location, product price and quality, appearance and cleanliness of stores and brand-name identification. Competition in the convenience store industry is intense. Within the travel center industry, Williams TravelCenters strives to be a market leader in customer service to the local consumer, traveling consumer and professional driver.

Williams Energy's gathering and processing facilities and natural gas liquids pipelines are owned in fee. Midstream Gas & Liquids constructs and maintains gathering and natural gas liquids pipeline systems pursuant to rights-of-way, easements, permits, licenses, and consents on and across properties owned by others. The compressor stations and gas processing and treating facilities are located in whole or in part on lands owned by subsidiaries of Williams Energy or on sites held under leases or permits issued or approved by public authorities.

Williams Energy owns its petroleum pipeline system in fee. However, a substantial portion of the system is operated, constructed and maintained pursuant to rights-of-way, easements, permits, licenses or consents on and across properties owned by others. The terminals, pump stations and all other facilities of the system are located on lands owned in fee or on lands held under long-term leases, permits or contracts. The North Pole Refinery is located on land leased from the state of Alaska under a long-term lease scheduled to expire in 2025 and renewable at that time by Williams Energy. The Anchorage, Alaska terminal is located on land leased from the Alaska Railroad Corporation under two long-term leases. The Memphis Refinery is located on land owned by Williams Energy. Williams Energy management believes its assets are in such a condition and maintained in such a manner that they are adequate and sufficient for the conduct of business.

Williams Energy Partners L.P. WEP competes with other independent terminal operators as well as integrated oil companies on the basis of terminal location and versatility, services provided and price. Its competition from independent operators primarily comes from distribution companies with marketing and trading arms, independent terminal operators and refining and marketing companies.

WEP competes primarily with ammonia shipped by rail carriers, but it has a distinct advantage over rail carriers because ammonia is a gas under normal atmospheric conditions and must be either placed under pressure or cooled to -33 degrees Celsius to be shipped or stored. WEP also competes to a limited extent in the areas served by the far northern segment of their ammonia pipeline and terminals system with the other United States ammonia pipeline, which originates on the Gulf Coast and transports domestically produced and imported ammonia.

ENVIRONMENTAL MATTERS

Williams Energy is subject to various international, federal, state and local laws and regulations relating to environmental quality control. Management believes that Williams Energy's operations are in substantial compliance with existing environmental legal requirements. Management expects that compliance with existing environmental legal requirements will not have a material adverse effect on the capital expenditures, earnings and competitive position of Williams Energy. See Note 19 of Notes to Consolidated Financial Statements.

The International unit must comply with the environmental laws of the country in which its assets are located. For example, Mazeikiu Nafta, a refinery located in Lithuania, must comply with its Permit for Use of Natural Resources issued by the government.

Groundwater monitoring and remediation are ongoing at both refineries and air and water pollution control equipment is operating at both refineries to comply with applicable regulations. The Clean Air Act Amendments of 1990 continue to impact Williams Energy's refining businesses through a number of programs and provisions. The provisions include Maximum Achievable Control Technology rules, which are being developed for the refining industry, controls on individual chemical substances, new operating permit rules and new fuel specifications to reduce vehicle emissions. The provisions impact other companies in the industry in similar ways and are not expected to adversely impact Williams Energy's competitive position.

Williams Energy and its subsidiaries also accrue environmental remediation costs for its natural gas gathering and processing facilities, natural gas liquids pipelines and storage facilities, petroleum products pipelines, retail petroleum and refining operations and for certain facilities related to former propane marketing operations primarily related to soil and groundwater contamination. In addition, Williams Energy owns a discontinued petroleum refining facility that is being evaluated for potential remediation efforts. At December 31, 2001, Williams Energy and its subsidiaries had accrued liabilities totaling approximately $43 million. Williams Energy accrues receivables related to environmental remediation costs based upon an estimate of amounts that will be reimbursed from state funds for certain expenses associated with underground storage tank problems and repairs.

WEG's operation of terminals and associated facilities in connection with the storage and transportation of crude oil and other liquid hydrocarbons, together with its operation of an ammonia pipeline, are subject to stringent and complex laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. As an owner or lessee and operator of these facilities, WEG must comply with these laws and regulations at the federal, state and local levels. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of remedial actions, and issuance of injunctions or construction bans or delays on ongoing operations.

OTHER INFORMATION

Williams believes that it has adequate sources and availability of raw materials and commodities to assure the continued supply of its services and products for existing and anticipated business needs. Williams' pipeline systems are all regulated in various ways resulting in the financial return on the investments made in the systems being limited to standards permitted by the regulatory bodies. Each of the pipeline systems has ongoing capital requirements for efficiency and mandatory improvements, with expansion opportunities also necessitating periodic capital outlays.

At December 31, 2001, Williams and its subsidiaries had approximately 12,433 full-time employees, of whom approximately 883 were represented by unions and covered by collective bargaining agreements. Williams' employees are jointly employed by Williams and one of its subsidiaries. Williams considers its relations with its employees to be generally good.

FORWARD-LOOKING STATEMENTS

Certain matters discussed in this report, excluding historical information, include forward-looking statements -- statements that discuss Williams' expected future results based on current and pending business operations. Williams makes these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "planned," "scheduled" or similar expressions. Although Williams believes these forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to a number of assumptions, uncertainties and risks that could cause future results to be materially different from the results stated or implied in this document.

Events in 2001 significantly impacted the risk environment all businesses face and raised a level of uncertainty in the capital markets that has approached that which lead to the general market collapse of 1929. Beliefs and assumptions as to what constitutes appropriate levels of capitalization and fundamental value have changed abruptly. The collapse of Enron combined with the meltdown of the telecommunications industry are both new realities that have had and will likely continue to have specific impacts on all companies, including Williams.

Following Enron's collapse, the credit rating agencies reacted by substantially shifting the financial criteria that companies must meet in order to support an investment grade credit rating. This change in criteria resulted in, among other things, the need for Williams to increase its equity by reducing its capital spending to a level that allows surplus cash to be generated and to issue new public equity. In addition, the credit rating agencies began to view credit rating downgrade triggers in financial structures as capable of producing an unpredictable event risk, so Williams committed to take action to eliminate credit rating triggers from certain of its financial structures. While Williams responded constructively to these new standards implemented by the credit rating agencies, there is no assurance that the credit rating agencies will not change the standards for maintaining an investment grade credit rating again in the future. The probability of the credit rating agencies changing the standards for maintaining an investment grade credit rating is high if the market remains unsettled or if additional Enron-like events occur.

The meltdown in the telecommunications and dot-com industry sectors combined with the Enron collapse caused lenders to become more conservative with respect to the credit exposure they were willing to take with regard to any company, including Williams. In some extreme cases, lenders sought ways to avoid honoring previous lending commitments or to restructure outstanding loans both by taking legal action and by creating credit or liquidity issues for companies by taking advantage of the heightened sensitivity of the markets to such issues. Williams can provide no assurance that its lenders will not respond in the same manner.

The equity markets have also become much more volatile and perception plays a much more important role in short-term market fluctuations than fundamentals. There is a pronounced downward bias in the markets. The hint of uncertainty or negative news regarding a company results in an abrupt loss of value in that company's stock. While markets have experienced such pressure before for limited periods of time, there is no assurance that the current uncertainty and negative bias will be temporary in nature.

Like its peers, business transactions in each of Williams' businesses, but especially in Williams' Energy Marketing & Trading business, will likely require greater credit assurances, both to be given from and received by Williams' to satisfy credit support requirements. If Williams' credit ratings were to decline below investment grade, its ability to participate in the Energy Marketing & Trading business could be significantly limited. Alternate credit support would be required under certain existing agreements and would be necessary to support future transactions. Without an investment grade rating, Williams would be required to fund margining requirements pursuant to industry standard derivative agreements with cash, letters of credit or other negotiable instruments. At December 31, 2001, the total notional amounts that would require such funding, in the event of a credit rating decline of Williams to below investment grade, is approximately $500 million, before consideration of offsetting positions and margin deposits from the same counterparties. Under extreme circumstances, the level of credit quality and assurances necessary to support the Energy Marketing & Trading business may reach a point that makes it impractical for Williams to continue to pursue the Energy Marketing & Trading business. In addition, the FERC's regulatory response to the events of 2001, including the California power crisis and Enron's bankruptcy, may make it impossible for Williams to conduct its Energy Marketing & Trading business along side its interstate natural gas pipelines business, which is subject to the FERC's direct jurisdiction.

A direct result of the highly-charged political environment caused by the Enron bankruptcy and the various perceived improper activities engaged in by Enron may be the proliferation of laws or regulations that could have a significant impact on the future conduct of all businesses. This proliferation of new laws and regulations may rival the laws and regulations that resulted from the Great Depression. These new laws and regulations could be mandated at the federal level through the legislature or federal agencies such as the Securities and Exchange Commission or Department of Labor, or from state legislatures and agencies. These new rules and regulations could, for example, cause companies to reexamine its employee benefit and compensation plans. More specifically, companies may determine that the risks of maintaining their 401(k) savings plans outweigh the benefits of the 401(k) savings plan to their employees. Other legislative and regulatory responses to the events of 2001 could increase the legal risk of participating on the board or acting as a senior officer of a publicly traded company impairing companies' ability to attract highly qualified individuals for these important positions. Under extreme circumstances, new laws and regulations which result from the events of 2001 could result in Williams adopting a risk avoidance strategy in pursuing its business which would impair its ability to make investments in the business that would provide growth for its shareholders and optimal service levels for its current and potential customers. At a minimum, Williams expects the cost of doing business to increase and the need to operate under more conservative financial structures as permanent outcomes of the current environment.

In addition to the collapse of Enron and the meltdown of the telecommunications industry, the security of our country has been challenged. It has been reported that terrorists may be targeting domestic energy facilities. While Williams is taking appropriate steps to increase the security of its energy assets, there is no assurance that Williams can completely secure its assets because it is impossible to completely protect against such an attack.

While Williams believes that it has the capacity to deal constructively with each of these possible impacts of the events of 2001, it is clear that a dramatic new level of uncertainty has been introduced. That uncertainty makes it impossible for Williams to predict outcomes with respect to any of these impacts with any meaningful level of confidence.

In addition to the factors discussed above, the following are important factors that could cause actual results to differ materially from any results projected, forecasted, estimated or budgeted:

- Changes in general economic conditions in the United States and changes in the industries in which Williams conducts business;

- Changes in federal or state laws and regulations to which Williams is subject, including tax, environmental and employment laws and regulations;

- The cost and effects of legal and administrative claims and proceedings against Williams or its subsidiaries;

- Conditions of the capital markets Williams utilizes to access capital to finance operations;

- The ability to raise capital in a cost-effective way;

- The effect of changes in accounting policies;

- The ability to manage rapid growth;

- The ability to control costs;

- The ability of each business unit to successfully implement key systems, such as order entry systems and service delivery systems;

- Changes in foreign economies, currencies, laws and regulations, and political climates, especially in Canada, Argentina, Brazil, Venezuela and Lithuania, where Williams has made direct investments;

- The impact of future federal and state regulations of business activities, including allowed rates of return, the pace of deregulation in retail natural gas and electricity markets, and the resolution of other regulatory matters discussed herein;

- Fluctuating energy commodity prices;

- The ability of Williams to develop expanded markets and product offerings as well as their ability to maintain existing markets;

- The ability of Williams and its subsidiaries to obtain governmental and regulatory approval of various expansion projects;

- The ability of customers of the energy marketing and trading business to obtain governmental and regulatory approval of various projects, including power generation projects;

- Future utilization of pipeline capacity, which can depend on energy prices, competition from other pipelines and alternative fuels, the general level of natural gas and petroleum product demand, decisions by customers not to renew expiring natural gas transportation contracts, and weather conditions;

- The accuracy of estimated hydrocarbon reserves and seismic data;

- The ability to successfully integrate any newly acquired businesses; and

- Global and domestic economic repercussions from terrorist activities and the government's response thereto.

(d) FINANCIAL INFORMATION ABOUT GEOGRAPHIC AREAS

See Item 1(c) for a description of Williams' international activities. See Note 22 for amounts of revenue and long-lived assets attributable to international activities.

ITEM 2. PROPERTIES

See Item 1(c) for a description of the locations and general character of the material properties of Williams and its subsidiaries.

ITEM 3. LEGAL PROCEEDINGS

For information regarding certain proceedings pending before federal regulatory agencies, see Note 19 of Notes to Consolidated Financial Statements. Williams is also subject to other ordinary routine litigation incidental to its businesses.

Environmental matters. Since 1989, Texas Gas and Transco have had studies under way to test certain of their facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests regarding such potential contamination of certain of its sites. The costs of any such remediation will depend upon the scope of the remediation. At December 31, 2001, these subsidiaries had accrued liabilities totaling approximately $33 million for these costs.

Certain Williams' subsidiaries, including Texas Gas and Transco have been identified as potentially responsible parties (PRP) at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws. Although no assurances can be given, Williams does not believe that these obligations or the PRP status of these subsidiaries will have a material adverse effect on its financial position, results of operations or net cash flows.

Transco, Texas Gas and Central have identified polychlorinated biphenyl (PCB) contamination in air compressor systems, soils and related properties at certain compressor station sites. Transco, Texas Gas and Central have also been involved in negotiations with the EPA and state agencies to develop screening, sampling and cleanup programs. In addition, negotiations with certain environmental authorities and other programs concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites have been commenced by Central, Texas Gas and Transco. As of December 31, 2001, Central had accrued a liability for approximately $9 million, representing the current estimate of future environmental cleanup costs to be incurred over the next six to ten years. Texas Gas and Transco likewise had accrued liabilities for these costs, which are included in the $33 million liability mentioned above. Actual costs incurred will depend on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

In July 1999, Transco received a letter stating that the DOJ, at the request of the EPA, intends to file a civil action against Transco arising from its waste management practices at Transco's compressor stations and metering stations in 11 states from Texas to New Jersey. Transco, the EPA and the DOJ agreed to settle this matter by signing a Consent Decree that provides for a civil penalty of $1.4 million.

Williams Energy and its subsidiaries also accrue environmental remediation costs for its natural gas gathering and processing facilities, petroleum products pipelines, retail petroleum and refining operations and for certain facilities related to former propane marketing operations primarily related to soil and groundwater contamination. In addition, Williams Energy owns a discontinued petroleum refining facility that is being evaluated for potential remediation efforts. At December 31, 2001, Williams Energy and its subsidiaries had accrued liabilities totaling approximately $43 million. Williams Energy accrues receivables related to environmental remediation costs based upon an estimate of amounts that will be reimbursed from state funds for certain expenses associated with underground storage tank problems and repairs. At December 31, 2001, Williams Energy and its subsidiaries had accrued receivables totaling $1 million.

Williams Field Services (WFS), a subsidiary of Williams Energy, received a Notice of Violation (NOV) from the EPA in February 2000. WFS received a contemporaneous letter from the DOJ indicating that DOJ will also be involved in the matter. The NOV alleged violations of the Clean Air Act at a gas processing plant. WFS, the EPA and the DOJ agreed to settle this matter for a penalty of $850,000. In the course of investigating this matter, WFS discovered a similar potential violation at the plant and disclosed it to the EPA and the DOJ. In December 2001, the EPA, DOJ and WFS agreed to settle this self-reported matter by signing a Consent Decree that provides for a civil penalty of $950,000.

In connection with the 1987 sale of the assets of Agrico Chemical Company, Williams agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations, to the extent such costs exceed a specified amount. At December 31, 2001, Williams had approximately $10 million accrued for such excess costs. The actual costs incurred will depend on the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from Williams' pipelines, pipeline systems and pipeline facilities used in the movement of oil or petroleum products, during the period July 1, 1998, through July 2, 2001. In November 2001, Williams furnished its response.

Other legal matters. In connection with agreements to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco and Texas Gas each entered into certain settlements with producers which may require the indemnification of certain claims for additional royalties which the producers may be required to pay as a result of such settlements. As a result of such settlements, Transco is currently defending three lawsuits brought by producers. In one of the cases, a jury verdict found that Transco was required to pay a producer damages of $23.3 million including $3.8 million in attorneys' fees. In addition, through December 31, 2001, post judgment interest was approximately $10.5 million. Transco's appeals have been denied by the Texas Court of Appeals for the First District of Texas, and on April 2, 2001, the company filed an appeal to the Texas Supreme Court. On February 21, 2002, the Texas Supreme Court denied Transco's petition for review. As a result, Transco recorded a pre-tax charge to income for the year ended December 31, 2001, in the amount of $37 million representing management's estimate of the effect of this ruling. Transco plans to request rehearing of the court's decision. In the other cases, producers have asserted damages, including interest calculated through December 31, 2001, of approximately $16.3 million. Producers have received and may receive other demands, which could result in additional claims. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the settlement between the producer and either Transco or Texas Gas. Texas Gas may file to recover 75 percent of any such additional amounts it may be required to pay pursuant to indemnities for royalties under the provisions of Order 528.

On June 8, 2001, 14 Williams entities were named as defendants in a nationwide class action lawsuit which has been pending against other defendants, generally pipeline and gathering companies, for more than one year. The plaintiffs allege that the defendants, including the Williams defendants, have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs. In September 2001, the plaintiffs voluntarily dismissed two of the 14 Williams entities named as defendants. In November 2001, Williams, along with other Coordinating Defendants, filed a motion to dismiss under Rules 9b and 12b of the Kansas Rules of Civil Procedure. In January 2002, most of the Williams defendants, along with a group of Coordinating Defendants, filed a motion to dismiss for lack of personal jurisdiction. The court has not yet ruled on these motions. In the next several months, the Williams entities will join with other defendants in contesting certification of the plaintiff class.

In 1998, the DOJ informed Williams that Jack Grynberg, an individual, had filed claims in the United States District Court for the District of Colorado under the False Claims Act against Williams and certain of its wholly owned subsidiaries including Central, Kern River, Northwest Pipeline, WGP, Transco, Texas Gas, WFS and Williams Production Company. Mr. Grynberg has also filed claims against approximately 300 other energy companies and alleges that the defendants violated the False Claims Act in connection with the measurement and purchase of hydrocarbons. The relief sought is an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys' fees, and costs. On April 9, 1999, the DOJ announced that it was declining to intervene in any of the Grynberg qui tam cases, including the action filed against the Williams entities in the United States District Court for the District of Colorado. On October 21, 1999, the Panel on Multi-District Litigation transferred all of the Grynberg qui tam cases, including those filed against Williams, to the United States District Court for the District of Wyoming for pre-trial purposes. Motions to dismiss the complaints, filed by various defendants, including Williams, were denied on May 18, 2001.

Between November 2000 and May 2001, class actions were filed on behalf of San Diego ratepayers against California power generators and traders including Williams Energy Marketing & Trading Company, a subsidiary of Williams. These lawsuits concern the increase in power prices in California during the summer of 2000 through the winter of 2000-01. The suits claim that the defendants acted to manipulate prices in violation of the California antitrust and business practice statutes and other state and federal laws. Plaintiffs are seeking injunctive relief as well as restitution, disgorgement, appointment of a receiver, and damages, including treble damages. These cases have been consolidated before the San Diego County Superior Court. Numerous other state and federal investigations regarding California power prices are also underway that involve Williams Energy Marketing & Trading Company.

Since January 29, 2002, Williams is aware of numerous shareholder class action suits that have been filed in the United States District Court for the Northern District of Oklahoma. The majority of the suits allege that Williams and co-defendants, Williams Communications and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002, known as the FELINE PACS offering. This case was filed against Williams, certain corporate officers, all members of the Williams board of directors and all of the offerings' underwriters. Williams does not anticipate any immediate action by the Court in these actions. In addition, class action complaints have been filed against Williams and the members of its board of directors under the Employee Retirement Income Security Act by participants in Williams' 401(k) plan based on similar allegations.

Summary

While no assurances may be given, Williams, based on advice of counsel, does not believe that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will have a materially adverse effect upon Williams' future financial position, results of operations or cash flow requirements.

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

Not applicable.

EXECUTIVE OFFICERS OF WILLIAMS

The names, ages, positions and earliest election dates of the executive officers of Williams are:

NAME	AGE	POSITIONS AND OFFICES HELD	HELD OFFICE SINCE
Gary R. Belitz	52	Controller -- Williams (Principal Accounting Officer)	01-01-92
William E. Hobbs	42	Chairman of the Board, President and Chief Executive Officer -- Williams Energy Marketing & Trading Company	02-04-00
Michael P. Johnson, Sr.	54	Senior Vice President, Human Resources -- Williams	05-01-99
Steven J. Malcolm	53	President and Director -- Williams (Principal Executive Officer)	09-21-01
		Chief Executive Officer	01-20-02
Jack D. McCarthy	59	Senior Vice President, Finance -- Williams (Principal Financial Officer)	01-01-92
William G. von Glahn	58	Senior Vice President and General Counsel -- Williams	08-01-96
J. Douglas Whisenant	55	President and Chief Executive Officer -- Williams Gas Pipeline Company, LLC	12-28-01
Phillip D. Wright	46	President and Chief Executive Officer -- Williams Energy Services, LLC	09-21-01

Except for Mr. Johnson, all of the above officers have been employed by Williams or its subsidiaries as officers or otherwise for more than five years and have had no other employment during the period. Prior to joining Williams, Mr. Johnson held various officer positions with Amoco Corporation for more than five years.

Mr. Keith E. Bailey resigned as Chief Executive Officer of Williams on January 20, 2002, but continues to serve as the Chairman of the Board.

PART II

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

Williams' common stock is listed on the New York and Pacific Stock exchanges under the symbol "WMB." At the close of business on December 31, 2001, Williams had approximately 15,017 holders of record of its Common Stock. The high and low closing sales price ranges (composite transactions) and dividends declared by quarter for each of the past two years are as follows:

	2001			2000		
QUARTER	HIGH	LOW	DIVIDEND	HIGH	LOW	DIVIDEND
1st	$45.90	$34.56	$.15	$48.69	$30.31	$.15
2nd	$43.55	$32.40	$.15	$44.50	$35.50	$.15
3rd	$33.97	$24.99	$.18	$47.63	$39.98	$.15
4th	$30.43	$22.10	$.20	$44.06	$31.81	$.15

Terms of certain subsidiaries' borrowing arrangements limit transfer of funds to Williams. These terms have not impeded, nor are they expected to impede, Williams' ability to meet its cash flow needs.

ITEM 6. SELECTED FINANCIAL DATA

The following financial data as of December 31, 2001 and 2000 and for the three years ended December 31, 2001 are an integral part of, and should be read in conjunction with, the consolidated financial statements and notes thereto. All other amounts have been prepared from the Company's financial records. Certain amounts below have been restated or reclassified (see Note 1). Information concerning significant trends in the financial condition and results of operations is contained in Management's Discussion & Analysis of Financial Condition and Results of Operations on pages 37 through 69 of this report.

	2001	2000	1999	1998	1997
	(MILLIONS, EXCEPT PER-SHARE AMOUNTS)				
Revenues(1)	$11,034.7	$9,591.9	$6,629.4	$5,660.0	$6,800.4
Income from continuing operations(2)	835.4	965.4	354.9	249.1	441.2
Loss from discontinued operations(3)	(1,313.1)	(441.1)	(198.7)	(122.0)	(10.7)
Extraordinary gain (loss)(4)	--	--	65.2	(4.8)	(79.1)
Diluted earnings (loss) per share:					
Income from continuing operations	1.67	2.15	.79	.56	1.02
Loss from discontinued operations	(2.62)	(.98)	(.44)	(.28)	(.03)
Extraordinary gain (loss)	--	--	.15	(.01)	(.18)
Total assets at December 31	38,906.2	34,776.6	21,682.1	17,900.2	15,802.6
Long-term debt at December 31	9,500.7	6,830.5	7,240.2	6,363.1	5,225.8
Preferred interests in consolidated subsidiaries at December 31	976.4	877.9	335.1	335.1	--
Williams obligated mandatorily redeemable preferred securities of Trust at December 31	--	189.9	175.5	--	--
Stockholders' equity at December 31(5)	6,044.0	5,892.0	5,585.2	4,257.4	4,237.8
Cash dividends per common share	.68	.60	.60	.60	.54

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(1) See Note 1 for discussion of change in management of certain operations, previously conducted by Energy Marketing & Trading, that were transferred to Petroleum Services. The sales activity which was transferred was previously reported on a "net" basis and is now reported on a "gross" basis. Also in 1998, there was a change in the reporting of certain marketing activities from a "gross" basis to a "net" basis consistent with fair value accounting.

(2) See Note 4 for discussion of write-downs of certain Williams Communications Group, Inc. (WCG) related assets in 2001 and see Note 5 for discussion of asset sales, impairments and other accruals in 2001, 2000 and 1999. Income from continuing operations in 1997 includes a $66 million pre-tax gain on the sale of Williams' interest in the natural gas liquids and condensate reserves in the West Panhandle field in Texas.

(3) See Note 3 for the discussion of the 2001, 2000 and 1999 losses from discontinued operations. The loss from discontinued operations for 1998 and 1997 relates to the operations of WCG and the sale of the MAPCO coal business.

(4) See Note 7 for discussion of the 1999 extraordinary gain. The extraordinary loss for 1998 and 1997 relates to redemption of higher interest rate debt.

(5) See Note 2 for discussion of the 2001 issuance of common stock for the Barrett acquisition, Note 3 for discussion of the WCG spinoff and Note 16 for discussion of Williams' January 2001 common stock issuance. See Note 3 for discussion of the 1999 issuance of subsidiary's common stock.

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

RECENT EVENTS

Since the fourth quarter 2001 events surrounding the Enron bankruptcy filing, Williams has been engaged in various discussions with investors, analysts, rating agencies and financial institutions regarding the liquidity implications of such to the business strategy of Williams' energy trading activities. More recently, Williams has also been evaluating its contingent obligations regarding guarantees and payment obligations with respect to certain financial obligations of Williams Communications Group, Inc. (WCG) because of uncertainty regarding its ability to perform. In addition, WCG has also announced that it is considering reorganizing under Chapter 11 bankruptcy laws. Both of these situations have resulted in rating agencies issuing statements in February 2002 confirming investment grade ratings, but with certain negative implications. Williams has announced that it is committed to strengthen its balance sheet and retain investment grade ratings and has taken significant steps since the first of the year to ensure that this occurs. Williams has a substantial and diverse asset base that provides strong support for its credit.

Following is a summary of the steps that are in progress which Williams believes will strengthen its balance sheet and ensure retention of its investment grade ratings.

- A $1 billion reduction in planned capital expenditures

- Generate proceeds from sales of assets during 2002

- Initiation of action to eliminate ratings triggers on certain obligations and contingencies that do not appear as debt on the Consolidated Balance Sheet, including the guarantees and payment obligations for WCG's debt

- A $50 million reduction from the company's cost structure pursuant to right-sizing the organization as an energy-only business

Each of these are discussed in more detail within the Liquidity and Other sections that follow.

GENERAL

On March 30, 2001, the board of directors of Williams approved a tax-free spinoff of Williams' communications business, WCG, to Williams' shareholders. On April 23, 2001, Williams distributed 398.5 million shares, or approximately 95 percent of the WCG common stock held by Williams, to holders of record of Williams common stock. As a result, the consolidated financial statements reflect WCG as discontinued operations.

In December 2001 and January 2002, the Securities and Exchange Commission (SEC) issued statements regarding disclosures by companies within their Management's Discussion & Analysis of Financial Condition and Results of Operations for 2001. In those statements, the SEC cited certain items that companies should consider including in the 2001 Form 10-Ks, including identification of critical accounting policies and expanded disclosure of certain liquidity matters, certain energy trading activities and transactions similar to related party activities. The following discussions include items that the SEC has encouraged companies to disclose.

Unless otherwise indicated, the following discussion and analysis of results of operations, financial condition and liquidity relates to the continuing operations of Williams and should be read in conjunction with the consolidated financial statements and notes thereto included in Item 8.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

Our financial statements reflect the selection and application of accounting policies which require management to make significant estimates and assumptions. We believe that the following are some of the more critical judgment areas in the application of our accounting policies that currently affect our financial condition and results of operations.

Revenue Recognition -- Gas Pipeline

Most of Gas Pipeline's businesses are regulated by the Federal Energy Regulatory Commission (FERC). The FERC regulatory processes and procedures govern the tariff rates that the Gas Pipeline subsidiaries are permitted to charge customers for natural gas sales and services, including the interstate transportation and storage of natural gas. Accordingly, certain revenues are collected by Gas Pipeline which may be subject to refunds upon final orders in pending rate cases with the FERC. In recording estimates of refund obligations, Gas Pipeline takes into consideration Gas Pipeline's and other third-parties regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection and other risks. At December 31, 2001, approximately $96 million was recorded as subject to refund, reflecting management's estimate of amounts invoiced to customers that may ultimately require refunding. Currently, certain of the Gas Pipeline subsidiaries are involved in rate case proceedings. Depending on the results of these proceedings, the actual amounts allowed to be collected from customers could differ from management's estimate.

Revenue Recognition -- Energy Marketing & Trading

Energy Marketing & Trading has energy risk management and trading operations that enter into energy contracts to provide price-risk management services to its customers. Energy and energy-related contracts utilized in energy risk management trading activities are recorded at fair value with the net change in fair value of those contracts representing unrealized gains and losses recognized in income currently. The fair value of energy and energy-related contracts is determined based on the nature of the transaction and the market in which transactions are executed. Certain contracts are executed in markets exchange traded or over-the-counter where quoted prices in active markets exist. Transactions are also executed in exchange-traded or over-the-counter markets for which market prices may exist however, the market may be inactive and price transparency is limited. Transactions are also executed for which quoted market prices are not available. Determining fair value for certain contracts involves complex assumptions and judgments when estimating prices at which market participants would transact if a market existed for the contract or transaction.

Certain energy-related contracts such as transportation, storage, load servicing and tolling arrangements require Energy Marketing & Trading to assess whether these contracts are executory service arrangements or leases pursuant to Statement of Financial Accounting Standards (SFAS) No. 13, "Accounting for Leases." Energy-related contracts that are determined to be executory contracts are accounted for at fair value. Currently, Williams does not account for any of the energy-related contracts as leases. There currently is not extensive authoritative guidance for determining when an arrangement is a lease or an executory service arrangement. As a result, Williams assesses each of its energy-related contracts and makes the determination based on the substance of each contract focusing on factors such as physical and operational control of the related asset, risks and rewards of owning, operating and maintaining the related asset and other contractual terms. The issue of whether contracts such as these energy-related contracts are an executory contract or a lease is currently being discussed by the Financial Accounting Standards Board's Emerging Issues Task Force. The discussions surrounding this issue are in the early stages of development and any consensus reached on these issues could ultimately impact Williams' accounting for these contracts.

Additional discussion of the accounting for energy and energy-related contracts at fair value is included in Note 1 of the Notes to Consolidated Financial Statements and pages 53 through 59 of Management's Discussion & Analysis of Financial Condition and Results of Operations.

Valuation of Deferred Tax Assets

Williams is required to assess the ultimate realization of deferred tax assets generated from the basis difference in certain investments and businesses. This assessment takes into consideration tax planning strategies, including assumptions regarding the availability and character of future taxable income. At December 31, 2001, Williams maintains $173.3 million of valuation allowances for deferred tax assets from basis differences in investments for which the ultimate realization of the tax asset may be dependent on the availability of future capital gains. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by potential changes in federal income laws and the circumstances upon the actual realization of related tax assets.

Impairment of Long-Lived Assets

Williams evaluates the long-lived assets, including other intangibles and related goodwill, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. In addition to those long-lived assets for which impairment charges were recorded (see Note 5), others were reviewed for which no impairment was required under a "held for use" computation. These computations utilized judgments and assumptions inherent in management's estimate of undiscounted future cash flows to determine recoverability of an asset. It is possible that a computation under a "held for sale" situation for certain of these long-lived assets could result in a significantly different assessment because of market conditions, specific transaction terms and a buyer's different viewpoint of future cash flows.

Contingent Liabilities

Williams establishes reserves for estimated loss contingencies when it is management's assessment that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are reflected in income in the period in which different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Reserves for contingent liabilities are based upon management's assumptions and estimates, advice of legal counsel or other third parties regarding the probable outcomes of the matter. Should the outcome differ from the assumptions and estimates, revisions to the estimated reserves for contingent liabilities would be required.

RESULTS OF OPERATIONS

CONSOLIDATED OVERVIEW

The following table and discussion is a summary of Williams' consolidated results of operations. The results of operations by segment are discussed in further detail beginning on page 42.

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
	(MILLIONS)		
Revenues	$11,034.7	$9,591.9	$6,629.4
Operating income	$ 2,450.0	$2,206.0	$1,166.6
Interest accrued -- net	(746.8)	(659.1)	(555.7)
Investing income (loss)	(198.4)	106.1	25.1
Preferred returns and minority interest in income of consolidated subsidiaries	(67.5)	(58.0)	(38.2)
Other income (expense) -- net	28.3	.3	(12.1)
Income from continuing operations before income taxes and extraordinary gain	1,465.6	1,595.3	585.7
Provision for income taxes	(630.2)	(629.9)	(230.8)
Income from continuing operations	835.4	965.4	354.9
Loss from discontinued operations	(1,313.1)	(441.1)	(198.7)
Income (loss) before extraordinary gain	(477.7)	524.3	156.2
Extraordinary gain	--	--	65.2
Net income (loss)	$ (477.7)	$ 524.3	$ 221.4

2001 vs. 2000

Consolidated Overview. Williams' revenues increased $1.4 billion, or 15 percent, due primarily to higher gas and electric power trading and services margins, a full year of Canadian operations within Midstream Gas & Liquids acquired in fourth-quarter 2000, higher petroleum products revenues, higher natural gas sales prices and revenues from Barrett Resources Corporation (Barrett) acquired in third-quarter 2001. In addition, the revenue increase includes the $582 million effect of reporting certain revenues net of the related costs in 2000 related to sales activity surrounding certain terminals. The revenues related to the sales activity around certain terminals are reported "gross" subsequent to the transfer of management over the sales activity from Energy Marketing & Trading to Petroleum Services effective February 2001 (see Note 1 of the Notes to Consolidated Financial Statements). Partially offsetting these increases was a decrease of $283 million in revenues related to the 198 convenience stores sold in May 2001, $116 million decrease in domestic natural gas liquids revenues and the effect in 2000 of a $74 million reduction of Gas Pipeline's rate refund liabilities.

Segment costs and expenses increased $1.2 billion, or 16 percent, due primarily to higher petroleum product costs, costs for a full year of Canadian operations acquired in fourth-quarter 2000, operating costs associated with Barrett acquired in third-quarter 2001 and the impact of reporting certain sales activity costs net with related revenues in 2000 (discussed above). Additionally, the increase reflects a $170 million impairment charge related to the Colorado soda ash mining facility within International. These increases were partially offset by a $286 million decrease in costs as a result of the sale of 198 convenience stores in May 2001 and the $75.3 million gain on the sale of these convenience stores.

Operating income increased $244.0 million, or 11 percent, due primarily to higher gas and electric power service margins, the $75.3 million pre-tax gain on the sale of the convenience stores in May 2001, higher margins at refining and marketing operations, increased realized natural gas sales prices, the impact of Barrett and the effect in 2000 of $63.8 million in guarantee loss accruals and impairment charges at Energy Marketing & Trading. Partially offsetting these increases were lower per-unit natural gas liquids margins at Midstream Gas & Liquids, the $170 million impairment charge within International, the $74 million effect in 2000 of reduction to rate refund liabilities and approximately $41 million of impairment charges and loss accruals within Energy Services. Included in operating income are general corporate expenses which increased $27.1 million, or 28 percent, due primarily to an increase in advertising costs (which includes a branding campaign of $12 million) and higher charitable contributions.

Interest accrued -- net increased $87.7 million, or 13 percent, due primarily to the $72 million effect of higher borrowing levels offset by the $48 million effect of lower average interest rates, $19 million in interest expense related to an unfavorable court decision involving Transcontinental Gas Pipe Line (Transco), a $14 million increase in interest expense related to deposits received from customers relating to energy risk management and trading and hedging activities, a $14 million increase in amortization of debt expense and a $4 million increase in interest expense on rate refund liabilities. The increase in long-term debt includes the $1.1 billion of senior unsecured debt securities issued in January 2001 and $1.5 billion of long-term debt securities issued in August 2001 related to the cash portion of the Barrett acquisition.

Investing income decreased $304.5 million, due primarily to fourth-quarter 2001 charges for a $103 million provision for doubtful accounts related to the minimum lease payments receivable from WCG, an $85 million provision for doubtful accounts related to a $106 million deferred payment for services provided to WCG and a $25 million write-down of the remaining investment basis in WCG common stock (see Note 3). In addition, the decrease also reflects a $94.2 million charge in third-quarter 2001, representing declines in the value of certain investments, including $70.9 million related to Williams' investment in WCG and $23.3 million related to losses from other investments, which were deemed to be other than temporary (see Note 4). In addition, the decrease in investing income reflects a $13 million decrease in dividend income due to the sale of the Ferrellgas Partners L.P. (Ferrellgas) senior common units in second-quarter 2001. The decreases to investing income (loss) were slightly offset by increased interest income of $17 million related to margin deposits. Preferred returns and minority interest in income of consolidated subsidiaries increased $9.5 million, or 16 percent, due primarily to preferred returns of Snow Goose LLC, formed in December 2000, and minority interest in income of Williams Energy Partners L.P., partially offset by a $10 million decrease of preferred returns related to the second-quarter 2001 redemption of Williams obligated mandatorily redeemable preferred securities of Trust.

Other income (expense) -- net increased $28 million due primarily to a $12 million increase in capitalization of interest on internally generated funds related to various capital projects at certain FERC regulated entities and $6 million lower losses from the sales of receivables to special purpose entities (see Note 18).

The provision for income taxes is comparable for both years. The effective income tax rate for 2001 is greater than the federal statutory rate due primarily to valuation allowances associated with the investing losses, for which no tax benefits were provided plus the effects of state income taxes. The effective income tax rate for 2000 is greater than the federal statutory rate due primarily to the effects of state income taxes.

Loss from discontinued operations for 2001 includes a $1.17 billion after-tax charge related to accruals for contingent obligations related to guarantees and payment obligations related to WCG and a $147.5 million after-tax loss from operations of WCG (see Note 3). The $441.1 million loss from discontinued operations for 2000 represents the after-tax losses from the operations of WCG.

2000 vs. 1999

Consolidated Overview. Williams' revenues increased $3 billion, or 45 percent, due primarily to higher revenues from natural gas and electric power services, increased petroleum products and natural gas liquids average sales prices and sales volumes and the contribution from Canadian operations within Midstream Gas & Liquids acquired in fourth-quarter 2000. Partially offsetting these increases were lower fleet management, retail natural gas, electric and propane revenues following the 1999 sales of these businesses.

Segment costs and expenses increased $1.9 billion, or 35 percent, due primarily to higher costs related to increased petroleum products and natural gas liquids average purchase prices and volumes purchased and costs related to the Canadian operations acquired in fourth-quarter 2000. Also contributing to the increases were higher variable compensation levels associated with improved performance and higher impairment charges and guarantee loss accruals at Energy Marketing & Trading. Partially offsetting these increases were lower fleet management, retail natural gas, electric and propane costs following the sales of these businesses in 1999.

Operating income increased $1.0 billion, or 89 percent, primarily reflecting improved natural gas and electric power services margins and higher per-unit natural gas liquids margins at Midstream Gas & Liquids, increased transportation demand revenues and the net effect of reductions to rate refund liabilities in 2000 over 1999, partially offset by higher variable compensation levels and the higher impairment charges and guarantee loss accruals in 2000. Included in operating income are general corporate expenses, which increased $20.3 million, or 26 percent, and include $15.2 million and $9.0 million in 2000 and 1999, respectively, of general corporate costs that would have otherwise been allocated to discontinued operations.

Interest accrued -- net increased $103.4 million, or 19 percent, due primarily to the $71 million effect of higher borrowing levels combined with the $49 million effect of higher average interest rates. These increases reflect the higher levels of short-term borrowing towards the end of 2000. Investing income (loss) increased $81 million due primarily to $33 million higher interest income, $28 million from higher net earnings from equity investments and $18 million higher dividend income associated primarily with the Ferrellgas senior common units.

Preferred returns and minority interest in income of consolidated subsidiaries increased $19.8 million. The change is due primarily to the preferred returns related to Williams obligated mandatorily redeemable preferred securities of Trust issued in December 1999.

The provision for income taxes increased $399.1 million primarily due to higher pre-tax income. The effective income tax rate in 2000 and 1999 exceeds the federal statutory rate due primarily to the effects of state income taxes.

Loss from discontinued operations includes the results of WCG in 2000 and 1999. WCG's losses in 2000 include a $323.9 million estimated pre-tax loss on disposal of a WCG segment that installs and maintains communications equipment and network services. In January 2001, WCG approved a plan for the disposal of its Solutions segment. Excluding the loss on disposal, WCG's pre-tax loss decreased $19.6 million as compared to 1999. Revenues increased over 1999 due primarily to growth in voice and data services partially offset by lower dark fiber revenue. WCG's expenses increased due primarily to the growth of network operations and infrastructure. WCG had increased operating losses as a result of providing customer services prior to completion of the new network, higher depreciation and network lease expense as the network is brought into service and higher selling, general and administrative expenses including costs associated with infrastructure growth and improvement. WCG also had higher interest expense as a result of increased debt levels in support of continued expansion and new projects. WCG's increased operating losses were substantially offset by higher investing income including a $214.7 million gain from the conversion of WCG's common stock investment in Concentric Network Corporation for common stock of XO Communications, Inc. (formerly Nextlink Communications, Inc.) pursuant to a merger of those companies in June 2000, net gains totaling $93.7 million from the sale of certain marketable equity securities, a $16.5 million gain on the sale of a portion of the investment in ATL-Algar Telecom Leste S.A. (ATL) and higher interest income. These were partially offset by $34.5 million of losses related to write-downs of certain cost basis and equity investments.

The $65.2 million 1999 extraordinary gain results from the sale of Williams' retail propane business (see Note 7).

Williams is organized into three industry groups: Energy Marketing & Trading, Gas Pipeline and Energy Services (includes Exploration & Production, International, Midstream Gas & Liquids, Petroleum Services, and Williams Energy Partners). Williams evaluates performance based upon segment profit (loss) from operations (see Note 22). The following discussions relate to the results of operations of Williams' segments.

ENERGY MARKETING & TRADING

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
		(MILLIONS)	
Segment revenues	$1,871.8	$1,572.6	$662.3
Segment profit	$1,271.5	$1,007.9	$104.0

2001 vs. 2000

Energy Marketing & Trading's revenues increased by $299.2 million or 19 percent in 2001, due to a $411 million increase in risk management and trading revenues, partially offset by a $112 million decrease in non-trading revenues.

The $411 million increase in risk management and trading revenues results primarily from an increase in risk management activities surrounding Energy Marketing & Trading's power tolling portfolio. As further discussed in Note 18 of the Notes to Consolidated Financial Statements, power tolling agreements provide Energy Marketing & Trading the right, but not the obligation, to call on the counterparty to convert natural gas to electricity at a predefined heat conversion rate. Energy Marketing & Trading benefited from higher natural gas and electric power services margins through the first quarter of 2001 from power tolling agreements previously recognized in 2000. Energy Marketing & Trading, through its origination of new contracts, executed several offsetting positions throughout the year to mitigate declines in these margins that occurred subsequent to the first quarter 2001. These new contracts consisted of full requirements, load serving and power supply agreements and typically have terms of up to 15 years (see Note 18). Execution of these contracts has the effect of reducing the risk of future changes in natural gas and power prices within the portfolio and also provides further insight into the prices for which third parties are willing to exchange in illiquid periods. This additional insight provides better information for the valuation of other existing contracts which generally has the effect of increasing the value recognized on these existing contracts. Subsequent to the execution of these origination transactions, natural gas and power prices declined dramatically. As a result of Energy Marketing & Trading's management strategies, this reduction had minimal impact to the overall portfolio fair value. Also contributing to the increase in the risk management and trading revenues during 2001 is an increase in successful forward natural gas financial trading.

Through a variety of energy commodity and derivative contracts, Energy Marketing & Trading has credit exposure to Enron and certain of its subsidiaries which have sought protection from creditors under Chapter 11 of the U.S. Bankruptcy Code. During fourth-quarter 2001, Energy Marketing & Trading recorded a reduction in trading revenues of approximately $130 million through the valuation of contracts with Enron. Approximately $91 million of this reduction in value was recorded pursuant to events immediately proceeding and following Enron's announced bankruptcy. At December 31, 2001, Williams has reduced its exposure to accounts receivable from Enron, net of margin deposits, to expected recoverable amounts.

Additional discussion of the accounting for energy risk management and trading activities at fair value is included in Note 1 of the Notes to Consolidated Financial Statements and pages 53 through 59 of Management's Discussion & Analysis of Financial Condition and Results of Operations.

The $112 million decrease in non-trading revenues is due primarily to declining prices on ethane and lower ethylene volumes and prices related to marketing of products of a petrochemical plant acquired by Williams in early 1999. These decreases were partially offset by a $4 million increase in non-trading power services revenues.

Costs and operating expenses decreased by $95 million, or 32 percent, due primarily to lower ethane, propane, and olefin prices in 2001, partially offset by higher cost of sales and operating expenses relating to the non-trading power services activities. These variances are associated with the corresponding changes in non-trading revenues discussed above.

Other (income) expense -- net in 2000 includes $47.5 million in guarantee loss accruals and impairment charges (see Note 5), a $16.3 million impairment of assets related to a distributed power generation business, and a $12.4 million gain on the sale of certain natural gas liquids contracts. Included in 2001, is a $13.3 million impairment of assets related to a terminated expansion project.

Segment profit increased $263.6 million due primarily to the $411 million higher trading revenues discussed above and the effect of the $63.8 million of guarantee loss accruals and impairment charges in 2000. Partially offsetting these increases were $141 million higher selling, general and administrative costs, $27 million lower margins from non-trading natural gas liquids operations, a $23.3 million loss from the write-downs of marketable equity securities and a cost-based investment (see Note 4), the $13.3 million impairment of assets related to a terminated expansion project, and the $12.4 million effect of the 2000 gain on sale of certain natural gas liquids contracts. The higher selling, general and administrative costs primarily reflect $40 million of higher variable compensation levels associated with improved operating performance, increased outside service costs, increased costs as a result of additional staff, as well as $13 million of increased charitable contributions to state universities, and $19 million of costs related to a European trading and marketing office in London which began operations in 2001.

2000 vs. 1999

Energy Marketing & Trading's revenues increased $910.3 million, or 137 percent, due to a $1,071 million increase in trading revenues partially offset by a $161 million decrease in non-trading revenues. The $1,071 million increase in trading revenues is due primarily to higher natural gas and electric power services margins. The higher gas and electric power services margins reflect the benefit of price volatility and increased demand for ancillary services, primarily in the western region of the United States, expanded price risk management services including higher structured transactions margins, increased overall market demand and increased trading volumes. The increased trading volumes and price risk management services reflect the expansion of the power trading portfolio to include an additional 2,350 megawatts from contracts giving Energy Marketing & Trading the right to market combined capacity from three power generating plants which were signed in late 1999 and early 2000. At December 31, 2000, Energy Marketing & Trading had rights to market 7,000 megawatts of electric generation capacity for periods ranging from 15 to 20 years. Of the 7,000 megawatts, approximately 4,000 megawatts are from facilities in California.

The $161 million decrease in non-trading revenues is due primarily to $226 million lower revenues following the sale of retail natural gas, electric and propane businesses in 1999, partially offset by $19 million higher revenues from a distributed power generation business that was transferred from Petroleum Services during 2000 and $33 million higher natural gas liquids revenues resulting from higher average sales prices and volumes attributable to marketing the products of a petrochemical plant that was acquired by Williams in early 1999.

Costs and operating expenses decreased $129 million, or 30 percent, due primarily to lower natural gas, electric and propane cost of sales and operating expenses of $112 million and $91 million, respectively, partially offset by $20 million higher cost of sales and operating expenses relating to the distributed power generation business and $25 million higher natural gas liquids cost of sales attributable to the petrochemical plant. These variances are associated with the corresponding changes in non-trading revenues discussed above.

Other (income) expense -- net changed unfavorably from income of $23 million in 1999 to expense of $48 million in 2000. The expense for 2000 includes $47.5 million of guarantee loss and impairment accruals (see Note 5) and a $16.3 million impairment of assets to fair value based on expected net proceeds related to management's decision and commitment to sell its distributed power generation business. Partially offsetting these 2000 charges was a $12.4 million gain on the sale of certain natural gas liquids contracts. Other (income) expense -- net in 1999 includes a $22.3 million gain on the sale of retail natural gas and electric operations.

Segment profit increased $903.9 million, from $104 million in 1999 to $1,007.9 million in 2000, due primarily to $1,073 million higher trading margins primarily related to natural gas and electric power services. Partially offsetting the higher margins were $66 million higher selling, general and administrative costs, the $47.5 million guarantee loss and impairment accruals, the $16.3 million impairment of the distributed power generation business, the $22.3 million gain in 1999 on sale of retail natural gas and electric operations and a $23 million lower contribution from retail natural gas, electric and propane following the sale of those businesses in 1999. The higher selling, general and administrative costs primarily reflect higher variable compensation levels associated with improved operating performance, partially offset by $40 million of selling, general and administrative costs related to the retail natural gas, electric and propane businesses sold in 1999.

Potential Impact of California Power Regulation and Litigation

At December 31, 2001, Energy Marketing & Trading had net accounts receivable recorded of approximately $388 million for power sales to the California Independent System Operator and the California Power Exchange Corporation (CPEC). While the amount recorded reflects management's best estimate of collectibility, future events or circumstances could change those estimates. In March and April of 2001, two California power-related entities, the CPEC and Pacific Gas and Electric Company (PG&E), filed for bankruptcy under Chapter 11. On September 20, 2001, PG&E filed a reorganization plan as part of its Chapter 11 bankruptcy proceeding that seeks to pay all of its creditors in full. California utility regulators agreed on October 2, 2001, to a settlement in which a Edison International unit, Southern California Edison, will repay its back debt out of existing rates by 2005. The agreement settles a federal-court lawsuit in which the utility sought to force the California Public Utilities Commission to raise rates and allows the utility to recover an estimated $3 billion in back debt. Both the reorganization plan and the settlement agreement are subject to current challenges, further legal proceedings and regulatory approvals. Williams does not believe its credit exposure to these utilities will result in a materially adverse effect on its results of operations or financial condition.

As discussed in Rate and Regulatory Matters and Related Litigation in Note 19 of the Notes to Consolidated Financial Statements, the FERC and the DOJ have issued orders or initiated actions which involve Williams Energy Marketing & Trading related to California and the western states electric power industry. In addition to these federal agency actions, a number of federal and state initiatives addressing the issues of the California electric power industry are also ongoing and may result in restructuring of various markets in California and elsewhere. Discussions in California and other states have ranged from threats of re-regulation to suspension of plans to move forward with deregulation. Allegations have also been made that the wholesale price increases resulted from the exercise of market power and collusion of the power generators and sellers, such as Williams. These allegations have resulted in multiple state and federal investigations as well as the filing of class-action lawsuits in which Williams is a named defendant (see Other Legal Matters in Note 19). Most of these initiatives, investigations and proceedings are in their preliminary stages and their likely outcome cannot be estimated. There can be no assurance that these initiatives, investigations and proceedings will not have an adverse effect on Williams' results of operations or financial condition.

GAS PIPELINE

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
		(MILLIONS)	
Segment revenues	$1,748.8	$1,879.2	$1,822.6
Segment profit	$ 720.1	$ 741.5	$ 697.3

2001 vs. 2000

Gas Pipeline's revenues decreased $130.4 million, or 7 percent, due primarily to the effect of a $74 million reduction of rate refund liabilities in 2000 following the settlement of prior rate proceedings, $72 million lower gas exchange imbalance settlements (offset in costs and operating expenses), $15 million lower recovery of tracked costs which are passed through to customers (offset in general and administrative expenses), and $10 million lower transportation revenues at Texas Gas due primarily to turnback capacity remarketed at discounted rates and for shorter contracted terms. Partially offsetting these decreases were $25 million higher gas transportation demand revenues as a result of new expansion projects and new rates on the Transco system and the California Action Project on the Kern River system and $9 million higher revenues from a liquefied natural gas storage facility acquired in June 2000.

Costs and operating expenses decreased $66 million, or 7 percent, due primarily to the $72 million lower gas exchange imbalance settlements (offset in revenues), $15 million resulting from the FERC's approval for recovery of fuel costs incurred in prior periods by Transco, and $6 million of accruals for gas exchange imbalances in 2000. Partially offsetting these decreases was $36 million in higher depreciation expense due to increased property, plant & equipment placed into service during 2001, which includes $16 million attributable to the California Action Project.

General and administrative costs decreased $22 million resulting primarily from lower tracked costs which are passed through to customers (offset in revenues) and costs in 2000 related to the headquarters consolidation of two of the gas pipelines, partially offset by higher charitable contributions.

Other (income) expense -- net for the year ended December 31, 2001, within segment costs and expenses includes a $27.5 million pre-tax gain from the sale of Williams' limited partnership interest in Northern Border Partners L.P. and a $3 million insurance settlement in 2001 for storage gas losses. Also included is an $18 million charge resulting from an unfavorable court decision in one of Transco's royalty claims proceedings (an additional $19 million is included in interest expense).

Segment profit decreased $21.4 million due primarily to the lower revenues discussed previously, partially offset by the lower costs and operating expenses, the items discussed previously in other (income) expense -- net, a $19 million increase in equity investment earnings from pipeline joint venture projects and the lower general and administrative expenses. The increase in equity investment earnings reflects $13 million from new projects which are primarily comprised of interest capitalized on internally generated funds as allowed by the FERC and a $6 million increase from earnings on existing projects.

2000 vs. 1999

Gas Pipeline's revenues increased $56.6 million, or 3 percent, due primarily to $74 million of rate refund liability reductions associated mainly with a favorable FERC order received in March 2000 by Transco related to the rate-of-return and capital structure issues in a regulatory proceeding. Revenues also increased due to $68 million higher gas exchange imbalance settlements (offset in costs and operating expenses), $23 million higher transportation demand revenues at Transco and $14 million higher storage revenues. Partially offsetting these increases were $66 million of reductions to rate refund liabilities in 1999 by four of the gas pipelines resulting primarily from second and fourth-quarter 1999 regulatory proceedings and $57 million lower reimbursable costs passed through to customers (offset in costs and operating expenses).

Segment profit increased $44.2 million, or 6 percent, due to $23 million higher transportation demand revenues at Transco, $18 million higher equity investment earnings from pipeline joint venture projects, the $8 million net effect of rate refund liability reductions discussed above and $3 million lower general and administrative expenses. The lower general and administrative costs reflect lower professional services costs associated with year 2000 compliance work, efficiencies realized from the headquarters consolidation of two of the pipelines and other cost reduction initiatives and the effect of a $2.3 million accrual in 1999 for damages associated with two pipeline ruptures in the northwest, partially offset by expenses related to the headquarters consolidation and higher charitable contributions in 2000. Partially offsetting the segment profit increases were $10 million higher depreciation expense primarily due to increased property, plant and equipment, and $6 million of accruals for gas exchange imbalances.

ENERGY SERVICES

EXPLORATION & PRODUCTION

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
	(MILLIONS)		
Segment revenues	$579.6	$294.2	$190.1
Segment profit	$218.7	$ 62.4	$ 39.8

2001 vs. 2000

Exploration & Production's revenues increased $285.4 million, or 97 percent, due primarily to $263 million higher production revenues including $119 million from increased net realized prices for production (including the effect of hedge positions) and $144 million associated with an increase in net volumes from production. Approximately $115 million of the $144 million increase relates to volumes associated with Barrett, which became a consolidated entity on August 2, 2001. Approximately 75 percent of production in 2001 was hedged. Exploration & Production has entered into contracts that hedge approximately 79 percent of projected 2002 natural gas production. These hedges are entered into with Energy Marketing & Trading which in turn, enters into offsetting derivative contracts with unrelated third parties. Energy Marketing & Trading bears the counterparty performance risks associated with unrelated third parties. During 2001, a portion of the external derivative contracts were with Enron, which filed for bankruptcy in December 2001. As a result, the contracts were effectively liquidated as a result of contractual terms about bankruptcy and Energy Marketing & Trading recorded estimated charges for the credit exposure. Under accounting guidance, the other comprehensive income related to a terminated contract remains in accumulated other comprehensive income and is recognized as the underlying volumes are produced. At December 31, 2001, approximately $80 million related to Enron was reflected in accumulated other comprehensive income. Energy Marketing & Trading has entered into derivative contracts to replace those contracts that were terminated during the year. At December 31, 2001, the contracted future hedges are at prices that averaged above the spot market, resulting in an unrealized gain of $331 million (including the $80 million previously discussed) reflected in other comprehensive income. Revenues from gas management activities increased $14 million. Gas management revenues consist primarily of marketing activities within the Exploration & Production segment that are not a direct part of the results of operations for producing activities. Those non-producing activities include acquisition and disposition of other working interest and royalty interest gas and the movement of gas from the wellhead to the tailgate of the respective plants for sale to Energy Marketing & Trading or third parties.

Segment costs and operating expenses increased $138 million, including a $22 million increase in selling, general and administrative expense. Segment costs and operating expenses increased due primarily to costs related to Barrett operations, comprised primarily of depreciation, depletion and amortization, lease operating expenses and gas management costs. In addition to the increase as a result of the Barrett acquisition, the higher segment costs and operating expenses reflect $10 million higher lease operating expenses, $8 million higher depreciation, depletion and amortization expenses and $6 million higher production-related taxes. Other income (expense) -- net in 2000 includes a $6 million impairment charge for certain gas producing properties. The charge represented the impairment of these held for sale assets to fair value based on expected net proceeds. These properties were sold in March 2001.

Segment profit increased $156.3 million due primarily to the higher production revenues in excess of costs. A major portion of this increase can be attributed to the Barrett acquisition. In addition, segment profit included $9 million in equity earnings from the 50 percent investment in Barrett held by Williams for the period from June 11, 2001 through August 2, 2001.

2000 vs. 1999

Exploration & Production's revenues increased $104.1 million, or 55 percent, due primarily to $65 million from increased average natural gas sales prices (net of the effect of hedge positions), $35 million associated with increases in both company-owned production volumes and marketing volumes from the Williams Coal Seam Gas Royalty Trust and royalty interest owners and an $8 million contribution in first-quarter 2000 of oil and gas properties acquired in April 1999. Exploration & Production hedged approximately 50 percent of production in 2000.

Other (income) expense -- net in 2000 includes a $6 million impairment charge relating to management's decision to sell certain gas producing properties. The charge represents the impairment of the assets to fair value based on expected net proceeds. Other (income) expense -- net in 1999 includes a $14.7 million gain from the sale of certain interests in gas producing properties which contributed $2 million to segment profit in 1999 and a $7.7 million gain from the sale of certain other properties.

Segment profit increased $22.6 million, or 57 percent, due primarily to the higher revenues discussed previously, partially offset by $43 million higher gas purchase costs related to the marketing of natural gas from the Williams Coal Seam Gas Royalty Trust and royalty interest owners, $22 million of gains on sales of assets in 1999, $10 million higher production-related taxes and the $6 million impairment charge in 2000.

INTERNATIONAL

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
	(MILLIONS)		
Segment revenues	$ 159.0	$104.1	$72.5
Segment profit (loss)	$(172.8)	$ 14.1	$(3.9)

2001 vs. 2000

International's revenues increased $54.9 million, or 53 percent, due primarily to $32 million of revenue from a new gas compression facility in Venezuela which began operations in August 2001 and $21 million of revenue from Colorado soda ash mining operations which began production in fourth-quarter 2000.

Costs and operating expenses increased $61 million, due primarily to $52 million related to soda ash mining operations and $13 million related to the new gas compression facility in Venezuela.

In fourth-quarter 2001, a $170 million impairment charge was recorded related to the Colorado soda ash mining operations. The facility experienced higher than expected construction costs and implementation difficulties through December 2001. As a result, an impairment of the assets based on management's estimate of the fair value was recorded in fourth-quarter 2001. Management's estimate was based on the present value of discounted future cash flows. In addition, management engaged an outside business consulting firm during fourth-quarter 2001 to provide further information to be utilized in management's estimation. Future events and the use of different judgments and/or assumptions could result in the recognition of a different level of impairment charge.

Segment profit decreased $186.9 million and is substantially related to the $170 million impairment of the soda ash mining facility mentioned above as well as additional losses from soda ash mining operations of $31 million, both of which are attributable to the operational and implementation complications since production began in late 2000. Equity losses increased $11 million due to an $8 million increase in equity losses from the Lithuanian refinery, pipeline and terminal investment and $6 million lower equity earnings from an Argentina oil and gas investment, partially offset by $3 million of equity earnings on an investment in a natural gas liquids (NGL) extraction and processing joint venture acquired in 2001. The Lithuanian refinery, pipeline and terminal investment continued to be challenged by a lack of market-priced crude oil supplies in the first-half of 2001. Additionally, a decrease in refinery crack spreads on the world market significantly contributed to the losses in 2001. Slightly offsetting these losses was an $18 million increase from a new Venezuelan gas compression facility which began operations in third-quarter 2001.

2000 vs. 1999

International's revenues increased $31.6 million, or 44 percent, due primarily to $17 million higher Venezuelan gas compression revenues reflecting higher volumes in 2000 following operational problems experienced in first-quarter 1999 and $11 million of higher revenues from oil and gas exploration operations in Argentina.

Costs and operating expenses increased $18 million due primarily to $8 million related to soda ash mining operations which began in fourth-quarter 2000, $5 million higher costs related to a Venezuelan gas compression facility and $3 million higher costs from oil and gas exploration operations in Argentina.

Segment profit increased $18 million due primarily to $14 million from increased operating income from Venezuelan gas compression operations, $8 million higher operating income from oil and gas exploration operations in Argentina and $5 million lower international equity investment losses, partially offset by a $7 million operating loss related to soda ash mining operations. The $5 million lower international equity investment losses reflect the change in accounting for an equity investment to a cost basis investment following a reduction of management influence and higher equity earnings from a South American equity investment. Partially offsetting these increases to equity earnings were higher equity losses from a Lithuanian refinery, pipeline and terminal investment acquired in fourth-quarter 1999, which continued to be challenged in obtaining market-priced crude oil supplies and had not yet consummated any long-term contracts.

MIDSTREAM GAS & LIQUIDS

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
		(MILLIONS)	
Segment revenues	$1,922.4	$1,514.7	$1,030.4
Segment profit	$ 221.6	$ 297.9	$ 223.9

2001 vs. 2000

Midstream Gas & Liquids' revenues increased $407.7 million, or 27 percent, due primarily to $564 million in revenues for the first three quarters of 2001 from Canadian operations that were acquired in October 2000. The $564 million of increased revenues from Canadian operations consists primarily of $270 million of natural gas liquids sales from processing activities, $205 million of natural gas liquids sales from fractionation activities, and $81 million of processing revenues. Canadian revenues decreased $57 million for the comparable periods of 2001 and 2000 due primarily to natural gas liquids product sales price decline.

Domestic natural gas liquids revenues decreased $116 million including $78 million from 15 percent lower volumes sold and $38 million due to lower average natural gas liquids sales prices. The 15 percent decrease in volumes sold is due primarily to less favorable processing economics. Domestic gathering revenues increased $11 million due primarily to higher volumes related to recent asset acquisitions in the Gulf Coast area.

Costs and operating expenses increased $456 million to $1.6 billion, due primarily to $549 million of costs and operating expenses related to the Canadian operations for the first three quarters of 2001 and $26 million higher domestic general operating and maintenance cost, partially offset by $58 million lower Canadian costs and operating expenses for the comparable periods of 2001 and 2000 due to lower shrink gas replacement costs, $38 million lower domestic shrink gas replacement costs, the effect in 2000 of $12 million of losses associated with certain propane storage transactions and $6 million lower domestic power costs related to the natural gas liquids pipelines.

General and administrative expenses decreased $2 million, or 2 percent, due primarily to $12 million of reorganization and early retirement costs incurred in 2000, substantially offset by $11 million of general and administrative expenses related to the Canadian operations for the first three quarters of 2001.

Included in other (income) expense -- net within segment costs and expenses for 2001 is $13.8 million of impairment charges related to management's 2001 decisions and commitments to sell certain south Texas non-regulated gathering and processing assets. The $13.8 million in impairment charges represent the impairment of the assets to fair value based on expected proceeds from the sales. These sales closed during first-quarter 2002.

Segment profit decreased $76.3 million, or 26 percent, due primarily to $54 million from lower average per-unit domestic natural gas liquids margins and $22 million from decreased domestic natural gas liquids volumes sold, $26 million higher domestic operating and maintenance costs, $13.8 million due to the impairment charge discussed above and $13 million higher losses from equity investments. Partially offsetting these decreases to segment profit were $14 million lower domestic general and administrative expenses, $11 million higher domestic gathering revenues, $12 million of losses associated with certain propane storage transactions during 2000 and $6 million lower domestic power costs related to the natural gas liquids pipelines.

2000 vs. 1999

Midstream Gas & Liquids' revenues increased $484.3 million, or 47 percent, due primarily to $267 million higher natural gas liquids sales from processing activities and $183 million in revenues from Canadian operations purchased in October 2000. The liquids sales increase reflects $172 million from a 49 percent increase in average natural gas liquids sales prices and $95 million from a 37 percent increase in volumes sold. The increase in natural gas liquids sales volumes result from improved liquids market conditions in 2000 and a full year of results from a plant that became operational in June 1999. The $183 million of revenues from the Canadian operations consist primarily of $165 million in natural gas liquids sales and $15 million of processing revenues. In addition, revenues increased due to $25 million higher natural gas liquids pipeline transportation revenues associated with increased shipments following improved market conditions and the completion of the Rocky Mountain liquids pipeline expansion in November 1999.

Costs and operating expenses increased $412 million, or 60 percent, due primarily to the $183 million of expenses related to the Canadian operations, $147 million higher liquids fuel and replacement gas purchases, $17 million higher power costs related to the natural gas liquids pipeline, $17 million in higher gathering and processing fuel costs due to increased natural gas prices and a full year of operation for two processing facilities, $15 million higher transportation, fractionation, and marketing expenses related to the higher natural gas liquid sales, $14 million higher depreciation expense, and $12 million of losses associated with certain propane storage transactions.

General and administrative expenses increased $11 million, or 11 percent, due primarily to $12 million of reorganization costs and $3 million associated with the Canadian operations purchased in 2000. The $12 million of reorganization costs relate to the reorganization of Midstream's operations including the consolidation in Tulsa of certain support functions previously located in Salt Lake City and Houston. In connection with this, Williams offered certain employees enhanced retirement benefits under an early retirement incentive program in first-quarter 2000, and incurred severance, relocation and other exit costs.

Segment profit increased $74 million, or 33 percent, due primarily to $81 million from higher per-unit natural gas liquids margins, $24 million from increased natural gas liquids volumes sold, $8 million lower equity investment losses mainly from the Discovery Pipeline project and $6 million from the natural gas liquids pipeline. Partially offsetting these increases to segment profit were $14 million higher depreciation expense, $17 million higher gathering and processing fuel costs, $12 million of propane storage losses and $11 million higher general and administrative expenses.

PETROLEUM SERVICES

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
		(MILLIONS)	
Segment revenues	$5,407.9	$4,605.0	$2,987.8
Segment profit	$ 286.9	$ 175.8	$ 157.8

Effective February 2001, management of refined product sales activities surrounding certain terminals throughout the United States was transferred to Petroleum Services from Energy Marketing & Trading (see Note 1). The sales activity was previously included in the trading portfolio of Energy Marketing & Trading and was therefore reported net of related cost of sales along with other refined product trading gains and losses within Energy Marketing & Trading prior to February 2001. After the transfer of management of these activities to Petroleum Services, these sales activities are reported "gross" within the Petroleum Services segment. Energy Marketing & Trading's revenues for the year ended December 31, 2000 includes approximately $582 million for both the sales and cost of sales related to this activity.

2001 vs. 2000

Petroleum Services' revenues increased $802.9 million, or 17 percent, and includes an increase to Petroleum Services' total revenues of $184 million as a result of lower intra-segment sales, which are eliminated, by refining and marketing to the travel centers/convenience stores. Additionally, revenues increased due to $596 million higher refining and marketing revenues partially offset by $60 million lower travel center/convenience store sales. The $596 million increase in refining and marketing revenues includes the $582 million impact discussed above and $340 million resulting from a 9 percent increase in refined product volumes sold, partially offset by $325 million from 8 percent lower average refined product sales prices. The $60 million decrease in travel center/convenience store sales reflects $223 million increase in revenues related to travel centers and Alaska convenience stores offset by a $283 million decrease in revenues related to the 198 convenience stores sold in May 2001. The $223 million increase in revenues of the travel centers and Alaska convenience stores reflects $243 million from a 31 percent increase in gasoline and diesel sales volumes and $41 million higher merchandise sales, partially offset by $61 million lower average diesel and gasoline sales prices. During 2001, Williams opened 12 travel centers. Previously announced plans to add 12 additional stores were deferred while a focus is placed on improving operating efficiencies and profitability at existing stores. In addition, revenues increased due to $99 million higher bio-energy sales reflecting increases in ethanol volumes sold and average ethanol sales prices and $28 million higher revenues from Williams' 3.1 percent undivided interest in Trans-Alaska Pipeline System (TAPS) acquired in late June 2000. Slightly offsetting these increases were $15 million lower revenues related to the petrochemical plant (Olefins) due to a plant turnaround in first-quarter 2001 and curtailed production.

Costs and operating expenses increased $757 million, or 18 percent, and include a $184 million increase in costs due to lower intra-segment purchases, which are eliminated. Additionally costs and operating expenses increased due to $526 million higher refining and marketing costs, partially offset by $29 million lower travel center/convenience store costs. The $526 million increase in refining and marketing costs includes the $582 million impact of the transfer of management from Energy Marketing & Trading to Petroleum Services discussed above, a $296 million increase in the cost of refined product purchased for resale and $17 million increase in other operating costs at the refineries, partially offset by a $369 million decrease from lower crude supply cost and other per unit cost of sales from the refineries. The refining and marketing costs include the impact of price risk management activities that are used to manage the economic exposure of fluctuations in commodity prices of crude oil and refined products. The $29 million decrease in travel center/convenience store costs reflects a $282 million decrease in costs related to the 198 convenience stores sold in May 2001, partially offset by a $253 million increase in costs related to travel centers and Alaska convenience stores. The $253 million increase in costs for the travel centers and Alaska convenience stores reflect $230 million from increased diesel and gasoline sales volumes, $60 million from higher store operating costs and $26 million higher merchandise costs, partially offset by $63 million lower gasoline and diesel purchase prices. In addition, costs and operating expenses increased due to $95 million higher bio-energy costs of sales.

Included in other (income) expense -- net within segment costs and expenses for 2001, is a $75.3 million gain from the sale of 198 convenience stores, primarily in the Tennessee metropolitan areas of Memphis and Nashville. Also included in other (income) expense -- net within segment costs and expenses in 2001 is a total of $14.7 million in loss accruals and impairment charges related to certain travel centers. This amount includes the estimated liability associated with the residual value guarantee of certain travel centers under an operating lease and the impairment of certain other travel centers to fair value based on management's estimate. Assessments for potential impairments are done on a store by store basis. Also included in other (income) expense -- net within segment costs and expenses in 2001 and 2000 are impairment charges of $12.1 million and $11.9 million, respectively, related to an end-to-end mobile computing systems business. The impairment charges result from management's decision in 2000 to sell certain of its end-to-end mobile computing systems and represents the impairment of the assets to fair value based on expected net sales proceeds, as revised. Other (income) expense -- net within segment costs and expenses in 2000 also included a $7 million write-off of a retail software system.

Segment profit increased $111.1 million, or 63 percent, due primarily to an increase of $71 million from refining and marketing operations and $17 million from Williams interest in TAPS acquired in late June 2000. In addition, segment profit increased due to a $75.3 million gain on the sale of convenience stores in May 2001. Partially offsetting these increases were a $32 million increase in operating losses from the travel centers and Alaska convenience stores, the $14.7 million in loss accruals and impairment charges related to certain travel centers and $17 million lower operating profit from activities at the petrochemical plant as revenues decreased due to plant turnaround and curtailed production without a corresponding decrease in cost.

2000 vs. 1999

Petroleum Services' revenues increased $1,617.2 million, or 54 percent, due primarily to $1,376 million higher refinery revenues (including $240 million higher intra-segment sales to the travel centers/convenience stores which are eliminated) and $455 million higher travel center/convenience store sales. The $1,376 million increase in refinery revenues reflects $1,113 million from 59 percent higher average refined product sales prices and $263 million from a 16 percent increase in refined product volumes sold. The increase in refined product volumes sold follows refinery expansions and improvements in mid-to-late 1999 and May 2000 which increased capacity. The $455 million increase in travel center/convenience store sales reflects $260 million from 32 percent higher average gasoline and diesel sales prices, $171 million primarily from a 64 percent increase in diesel sales volumes and $24 million higher merchandise sales. The increase in diesel sales volumes and the higher merchandise sales reflect the opening of eight new travel centers since fourth-quarter 1999. Slightly offsetting these increases were $91 million lower fleet management revenues following the sale of a portion of such operations in late 1999, $21 million lower distribution revenues due to a reduction of a propane trucking operation and $16 million lower pipeline construction revenues following substantial completion of the Longhorn pipeline project.

In December 2000, Williams signed an agreement to sell 198 of its convenience stores, primarily in the Tennessee metropolitan areas of Memphis and Nashville. Revenues related to these convenience stores for 2000 and 1999 were $466 million and $453 million, respectively. The sale closed in May 2001.

Costs and operating expenses increased $1,568 million, or 58 percent, due primarily to $1,349 million higher refining costs and $470 million higher travel center/convenience store costs (including $240 million higher intra-segment purchases from the refineries which are eliminated). The $1,349 million increase in refining costs reflects $1,088 million from higher crude supply costs and other related per-unit cost of sales, $221 million associated with increased volumes sold and $40 million higher operating costs at the refineries. The $470 million increase in travel center/convenience store costs includes $273 million from higher average gasoline and diesel purchase prices, $159 million primarily from increased diesel sales volumes and $38 million higher store operating costs. Slightly offsetting these increases were $101 million lower fleet management operating costs following the sale of a portion of such operations in late 1999, $18 million lower cost of distribution activities following a reduction of a propane trucking operation and $14 million lower pipeline construction costs following substantial completion of the Longhorn pipeline project.

Other (income) expense -- net for 2000 includes a $11.9 million impairment charge related to end-to-end mobile computing systems and a $7 million write-off of a retail software system. The impairment charge results from management's decision to sell certain of its end-to-end mobile computing systems and represents the impairment of the assets to fair value based on expected net sales proceeds. The primary component in other (income) expense -- net for 1999 was a $6.5 million favorable effect of settlement of transportation pipeline rate case issues.

Segment profit increased $18 million, or 11 percent, due primarily to $42 million from increased refined product volumes sold and $25 million from increased per-unit refinery margins, partially offset by $40 million higher operating costs at the refineries. In addition, segment profit increased $18 million from bio-energy operations primarily reflecting increased ethanol sales prices and volumes, $10 million from the absence of certain fleet management losses in 2000, $8 million from Williams' interest in the TAPS acquired in late June 2000 and $8 million from activities at the petrochemical plant acquired in March 1999. Partially offsetting these increases to segment profit were a $6 million lower contribution from transportation activities and a lower contribution from the travel centers/convenience stores which had $38 million higher operating costs partially offset by a $24 million increase in gross profit on merchandise sales. In addition, segment profit in 2000 was decreased by $6 million higher selling, general and administrative expense and the $25 million unfavorable change in other (income) expense -- net discussed previously.

WILLIAMS ENERGY PARTNERS

	YEARS ENDED DECEMBER 31,		
	2001	2000	1999
	(MILLIONS)		
Segment revenues	$86.2	$73.5	$43.6
Segment profit	$17.0	$21.8	$16.3

2001 vs. 2000

Williams Energy Partners' revenues increased $12.7 million due primarily to the acquisition of a marine terminal facility in September 2000 and higher revenues and rates from the storage of petroleum products at the Gulf Coast marine facilities. Segment profit decreased $4.8 million due primarily to higher operating costs related to the marine facilities discussed above and higher general and administrative expenses.

2000 vs. 1999

Williams Energy Partners' revenues increased $29.9 million due primarily to the acquisition of three Gulf Coast marine facilities in August 1999, one inland terminal in March 2000, and another marine terminal in September 2000. Operating costs and selling, general and administrative expenses increased $18.1 million and $6.3 million respectively, due to the five terminals acquired above. Segment profit increased $5.5 million due primarily to the profit generated from the new terminals.

FAIR VALUE OF ENERGY RISK MANAGEMENT AND TRADING ACTIVITIES

As more thoroughly described in Note 1 of the Notes to Consolidated Financial Statements, energy and energy-related contracts are valued at fair value and, with the exception of certain commodity inventories, are recorded in current and noncurrent energy risk management and trading assets and liabilities in the Consolidated Balance Sheet. Fair value of energy and energy-related contracts is determined based on the nature of the transaction and market in which transactions are executed. Certain transactions are executed in exchange-traded or over-the-counter markets for which quoted prices in active periods exist. Transactions are also executed in exchange-traded or over-the-counter markets for which quoted market prices may exist, however, the market may be inactive and price transparency is limited. Certain transactions are executed for which quoted market prices are not available.

METHODS OF ESTIMATING FAIR VALUE

Quoted prices in active markets

Quoted market prices for varying periods in active markets are readily available for valuing forward contracts, futures contracts, swap agreements and purchase and sales transactions in the commodity markets in which Energy Marketing & Trading transacts. These prices reflect the economic and regulatory conditions that currently exist in the market place and are subject to change in the near term due to changes in future market conditions. The availability of quoted market prices in active markets varies between periods and commodities based upon changes in market conditions.

Quoted prices and other external factors in less active markets

For contracts or transactions extending into periods for which actively quoted prices are not available, Energy Marketing & Trading estimates energy commodity prices in these illiquid periods by incorporating information about commodity prices in actively quoted markets, quoted prices in less active markets, and other market fundamental analysis. While an active market may not exist for the entire period, quoted prices can generally be obtained for natural gas and power through 2008, crude and refined products through 2004, and natural gas liquids through 2003. Prices reflected in current transactions executed by Energy Marketing & Trading are used to further validate the estimates of these prices.

Models and other valuation techniques

Contracts for which quoted market prices are not available primarily include transportation, storage, full requirements, load serving and power tolling contracts (energy-related contracts). A description of these contracts is included in Note 18 of the Notes to Consolidated Financial Statements. Energy Marketing & Trading estimates fair value using models and other valuation techniques that reflect the best available information under the circumstances. The valuation techniques incorporate option pricing theory, statistical and simulation analysis, present value concepts incorporating risk from uncertainty of the timing and amount of estimated cash flows and specific contractual terms. Factors utilized in the valuation techniques include quoted energy commodity market prices, estimates of energy commodity market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors underlying the positions, estimated correlation of energy commodity prices, contractual volumes, estimated volumes, liquidity of the market in which the contract is transacted and a risk premium that market participants would consider in their determination of fair value. Although quoted market prices are not available for these energy-related contracts themselves, quoted market prices for the underlying energy commodities are a significant component in the valuation of these contracts.

Each of the methods discussed above also include counterparty performance and credit consideration in the estimation of fair value.

The chart below reflects the fair value of Energy Marketing & Trading's energy risk management and trading contracts at December 31, 2001 by valuation methodology and the year in which the recorded fair value is expected to be realized.

	PERIOD FAIR VALUE IS EXPECTED TO BE REALIZED IN CASH					
VALUATION METHOD:	2002	2003-2004	2005-2006	2007-2011	2012+	TOTAL
	(MILLIONS)					
Based upon quoted prices in active markets and quoted prices and other external factors in less active markets(1)	$757	$316	$345	$363	$ 18	$1,799
Based upon models and other valuation techniques(2)	231	12	(19)	50	188	462
Total(3)	$988	$328	$326	$413	$206	$2,261
% of fair value to be realized by period	44%	15%	14%	18%	9%	100%

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(1) A significant portion of the value expected to be realized relates to a contract within the California power market. The terms of this contract provide for the sale of power at prices ranging from $62.50 to $87.00 per megawatt hour over a ten-year period at variable volumes up to 1,400 megawatts per hour.

(2) Quoted market prices of the underlying commodities are a significant factor in the estimate of fair value.

(3) Approximately $1.1 billion of the value expected to be realized through 2010 has been managed in a manner whereby offsetting fixed price energy and energy-related contracts mitigate the exposure to changes in fair value resulting from future changes in commodity prices.

SIGNIFICANT ESTIMATES AND ASSUMPTIONS USED IN THE VALUATION ESTIMATION PROCESS

Estimates of fair value for long-term energy and energy-related contracts are most significantly impacted by management's estimates and assumptions in the illiquid periods. However, the impact of these estimates and assumptions on the fair value of contracts is reduced to the extent Energy Marketing & Trading has managed the portfolio by executing offsetting fixed price energy and energy-related contracts to mitigate exposure in the portfolio to changes in fair value resulting from future changes in commodity prices.

The most significant estimates and assumptions include:

- Estimates of natural gas and power market prices in illiquid periods;

- Estimates of volatility and correlation of natural gas and power prices;

- Estimates of risk inherent in estimating cash flows; and

- Estimates and assumptions regarding counterparty performance and credit considerations.

Estimates of natural gas and power market prices in illiquid periods

Natural gas and power prices are the most significant commodity prices impacting the fair value of Energy Marketing & Trading contracts at December 31, 2001. In estimating natural gas and power prices during illiquid periods, Energy Marketing & Trading includes factors such as quoted market prices, prices of current market transactions and market fundamental analysis. Market fundamental analysis incorporates the most recent market data from industry publications, regulatory publications, existing and forecasted electricity generation capacity, natural gas reserve data, alternative fuel source availability, weather patterns and other indicative information supporting supply and demand relationships. These estimated market prices are highly dependent upon actively quoted market prices for natural gas and power, current economic and regulatory conditions, as well as, information supporting future conditions that would affect the supply and demand relationships.

As new information is obtained about market prices during illiquid periods, Energy Marketing & Trading incorporates this information in its estimates of market prices. Such new information includes additional executed transactions extending into these periods. These transactions give insight into the market prices for which market participants are willing to buy or sell in arms-length transactions.

Estimation of volatility and correlation of natural gas and power prices

Volatility of natural gas and power prices represents a significant assumption in the determination of fair value of contracts that contain optionality and whose fair value is estimated using option-pricing models. Correlation of natural gas and power prices represents a significant assumption in the determination of fair value of contracts that contain optionality and involve multiple commodities and whose fair value is estimated using option-pricing models. Volatility and correlation can be implied from option based market transactions during periods when quoted market prices exist for natural gas and power. Volatility and correlation is estimated in periods during which quoted market prices are not available through quantitative analysis of historical volatility patterns of the commodities, expected future changes in estimated natural gas and power prices, and market fundamental analysis. Estimates of volatility and correlation significantly impact the estimation of fair value for all periods in which the contract is valued using option-pricing models.

Estimates of risk inherent in estimating cash flows

Risk inherent in estimating cash flows represents the uncertainty of events occurring in the future which could ultimately affect the realization of cash flows. Energy Marketing & Trading estimates the risk active market participants would include in the price exchanged in an arms-length transaction in the estimation of fair value for each contract. Energy Marketing & Trading estimates risk utilizing the capital asset pricing theory in the estimation of fair value of energy-related contracts. The capital asset pricing theory considers that investors require a higher return for contracts perceived to embody higher risk of uncertainty in the market. This risk is most significant in illiquid periods and markets. Factors affecting the estimate of risk include liquidity of the market in which the contract is executed, ability to transact in future periods, existence of similar transactions in the market, uncertainty of timing and amounts of cash flows, and market fundamental analysis.

Estimates and assumptions regarding counterparty performance and credit considerations

Energy Marketing & Trading includes in its estimate of fair value for all contracts an assessment of the risk of counterparty non-performance. Such assessment considers the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor's and Moody's Investor's Service, the inherent default probabilities within these ratings, the regulatory environment that the contract is subject to, as well as the terms of each individual contract.

The counterparties associated with assets from energy trading and price-risk management activities as of December 31, 2001, are summarized as follows:

	INVESTMENT GRADE(A)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 4,253.9	$ 4,924.5
Energy marketers and traders	5,645.5	6,058.2
Financial institutions	249.8	341.7
Other	16.4	47.3
Total	$10,165.6	11,371.7
Credit reserves		(648.2)
Assets from energy risk management and trading activities(b)		$10,723.5

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(a) "Investment Grade" is primarily determined using publicly available credit ratings along with consideration of cash, standby letters of credit, parent company guarantees, and property interests, including oil and gas reserves. Included in "Investment Grade" are counterparties with a minimum Standard & Poor's and Moody's Investor's Service rating of BBB- or Baa3, respectively.

(b) One counterparty within the California power market represents greater than ten percent of assets from energy risk management and trading activities and is included in "investment grade." Standard & Poor's and Moody's Investor's Service do not rate this counterparty. This counterparty has been included in the "investment grade" column as a result of the manner in which it was established by the State of California.

As further discussed in Note 19 of the Notes to Consolidated Financial Statements, the electricity markets in California continue to be subject to numerous and wide-ranging regulatory proceedings and investigations, regarding among other things, market structure, behavior of market participants and market prices. Energy Marketing & Trading has considered counterparty performance as a result of ongoing issues in the California power industry that could result in a restructuring of the California markets. The risk of non-performance surrounding this issue is updated as new information regarding the status of these issues occurs.

CONTROLS AROUND VALUATION ESTIMATION PROCESS

Information used in determining the significant estimates and assumptions utilized in the determination of fair value of energy-related contracts is derived from market fundamental analysis. Interpreting this data requires judgement and Energy Marketing & Trading recognizes that others in the market place might interpret this data differently. It is reasonably possible that different interpretations of this data could result in a different estimation of fair value in periods for which estimates and assumptions are significant components of estimating fair value. In estimating fair value, Energy Marketing & Trading considers how we believe others in the market place would interpret this information in order to further validate that the estimates and assumptions used in estimating fair value provides the best estimate of the amount that active market participants would exchange in an arms-length transaction. Once offsetting contracts are entered into to mitigate commodity price risk, the reliance on management's assumptions and estimates utilized in the estimation of the fair value of each contract becomes less significant. However, the assumptions and estimates surrounding counterparty performance and credit are still an integral component in the estimation of fair value for these contracts. Energy Marketing & Trading enhances its valuation techniques, models and significant estimates and assumptions as better information about the markets in which Energy Marketing & Trading transacts becomes available.

Energy Marketing & Trading maintains a control environment surrounding the operational and valuation processes through its trading policy, credit policy, and general controls involved in the daily operations of the business. These policies provide limits on the types of transactions that can be executed, including term of the contract, the volumetric size of the contract and commodities underlying the contract. The policies also provide limits on the amount of credit extended to a single counterparty, the gross value at risk of the overall portfolio and the maximum daily loss permitted within the portfolio. These policies have been approved by Williams' Board of Directors and are administered through the Williams Risk Management Committee consisting of Energy Marketing & Trading's Risk Control Officer and other members of Williams' senior management. The Risk Control Officer is responsible for Energy Marketing & Trading's Risk Control Group who monitors the compliance with these policies and controls on a daily basis. The Risk Control Group reports instances in which limits are exceeded or other significant exceptions to the policies occur to members of the Risk Management Committee. A notification of noncompliance also includes a plan to remedy the exception in order to bring the portfolio back into the approved limits and standards.

Energy Marketing & Trading's Risk Control Group also performs validations of the valuation techniques, models and significant estimates and assumption on a quarterly basis in order to provide additional assurance that the estimates of fair value provide the best determination of how others in the market might value the contracts. Validations include functions such as comparing third party market quotes against estimated prices, comparing contractual terms to those input into the models, reviewing the market fundamental analysis for reasonableness and recalculating the significant computations.

MANAGEMENT OF RISK IN PORTFOLIO

Energy Marketing & Trading manages the risk assumed from providing energy risk management services to its customers. This risk results from exposure to energy commodity prices, volatility and correlation of commodity prices, the portfolio position of the contracts, liquidity of the market in which the contract is transacted, interest rates, and counterparty performance and credit. Energy Marketing & Trading actively seeks to diversify its portfolio in managing the commodity price risk in the transactions that it executes in various markets and regions by executing offsetting contracts to manage the commodity price risk in accordance with parameters established in its trading policy. As of December 31, 2001, approximately $1.1 billion of the value expected to be realized through 2010 has been managed in a manner whereby fixed-price energy and energy-related contracts mitigate the exposure in the portfolio to changes in fair value resulting from future changes in commodity prices.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of the cash flows expected to be realized. Energy Marketing & Trading continually assesses this risk and has credit protection within various agreements to call on additional collateral support in the event of changes in the creditworthiness of the counterparty. Additional collateral support could include letters of credit, payment under margin agreements, guarantees of payment by creditworthy parties, or in some instances, transfers of the ownership interest in natural gas reserves or power generation assets. In addition, Energy Marketing & Trading enters into netting agreements to mitigate counterparty performance and credit risk. Credit default swaps may also be used to manage the counterparty credit exposure in the energy risk management and trading portfolio. Under these agreements, Energy Marketing & Trading pays a fixed rate premium for a notional amount of risk coverage associated with certain credit events on a referenced obligation. The covered credit events are bankruptcy, obligation acceleration, failure to pay, and restructuring.

Energy Marketing & Trading, through Williams, also enters into interest rate swaps to mitigate the associated interest rate risk from the fair value of the long dated energy and energy-related contracts by fixing the interest rate inherent in the portfolio of contracts. At December 31, 2001, Energy Marketing & Trading had executed interest rate swaps to offset potential interest rate changes for approximately $1 billion of the expected future cash flows in its portfolio.

CHANGES IN FAIR VALUE DURING 2001

The following table reflects the changes in fair value between December 31, 2000 and 2001.

		(MILLIONS)
Fair value of contracts outstanding at December 31, 2000		$ 811
Fair value of contracts outstanding at December 31, 2000 expected to be realized during 2001	$(282)	
Initial recorded value of new contracts entered into during 2001	360	
Changes in fair values attributable to change in valuation techniques	77	
Change in net option premiums paid and received	733	
Changes attributable to market movements	562	
Total change in fair value during 2001		1,450
Fair value of contracts outstanding at December 31, 2001		$2,261

The following table reconciles the changes in fair value of energy risk management and trading contracts during 2001 to energy risk management trading revenues for the period ending December 31, 2001.

	(MILLIONS)
Change in fair value during 2001	$1,450
Change in net option premiums paid and received	(733)
Fair value of contracts outstanding at December 31, 2000 expected to be realized during 2001	282
Net change in fair value impacting revenues	999
Revenues recognized and realized during 2001(1)	697
Energy risk management and trading revenues during 2001(2)	$1,696

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(1) Represents the change in fair value of energy and energy-related contracts outstanding at December 31, 2000 that were realized during 2001, as well as, contracts entered into during 2001 and settled prior to December 31, 2001.

(2) Reflects only revenues from energy risk management and trading activities accounted for on a fair value basis. This amount excludes approximately $176 million of non-trading related revenues accounted for on an accrual basis.

Changes in fair value during 2001 include the realization of cash flows on contracts outstanding at December 31, 2000 that were expected to be realized during 2001. These amounts may have differed from the values that were actually realized during 2001 due to changes in market prices and other factors that occurred during 2001 prior to the realization of those cash flows.

During 2001, Energy Marketing & Trading recognized revenues resulting from the execution of new long-term contracts providing for energy price risk management services to customers. See Energy Marketing & Trading's 2001 Results of Operations for a discussion of the type of contracts executed during the year. The fair value of new contracts at the time they are executed reflect the prices negotiated in long-term contracts which includes the premium Energy Marketing & Trading receives for managing the energy price risk of its customers. Additionally, as further discussed in Note 1 of the Notes to Consolidated Financial Statements, Energy Marketing & Trading does not recognize revenue on contracts until all requirements for revenue recognition have been achieved. As a result, the fair value of these contracts at the time they were executed is likely to differ from the fair value of the contracts at the time they were initially recorded in the financial statements due to changes in market prices and other factors which may have occurred during such period.

Energy Marketing & Trading continuously evaluates the valuation techniques and models used in estimating fair value and modifies and implements new valuation techniques based upon emerging financial theory in order to provide a better estimate of fair value.

A component of the fair value of energy risk management and trading assets and liabilities includes the amount of cash received and cash paid for premiums on option contracts. Premiums for options contracts impact energy trading revenues over the life of the option contract. At December 31, 2001, approximately $881 million of the net energy risk management and trading assets and liabilities included cash payments for premiums on option contracts purchased by Energy Marketing & Trading in excess of cash received for options sold.

Changes attributable to market movements reflect the change in fair value of contracts resulting from changes in quoted market prices of commodities, interest rates, volatility and correlation of commodity prices. This also includes improvements in the estimates and assumptions Energy Marketing & Trading uses in estimating fair value based upon new information and data available in the marketplace. The most significant component of these changes during 2001 occurred during the first quarter and prior to the execution of certain offsetting contracts mitigating the exposure in the portfolio to changes in fair value from future changes in commodity prices.

FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY

Williams considers its liquidity to come from both internal and external sources. Certain of those sources are available to Williams (parent) and certain of its subsidiaries. Williams' unrestricted sources of liquidity, which Williams believes can be utilized without limitation under existing loan covenants, consist primarily of the following:

- Available cash equivalent investments of $1.1 billion at December 31, 2001, as compared to $854 million at December 31, 2000.

- $700 million available under Williams' $700 million bank-credit facility at December 31, 2001, as compared to $350 million at December 31, 2000.

- $769 million available under Williams' $2.2 billion commercial paper program (or the related bank-credit facility) at December 31, 2001, as compared to $4 million at December 31, 2000 under a $1.7 billion commercial paper program.

- Cash generated from operations.

- Short-term uncommitted bank lines of credit may also be used in managing liquidity.

The availability of borrowings under Williams' $700 million bank-credit facility and Williams' $2.2 billion bank credit facility which supports the $2.2 billion commercial paper program is subject to specified conditions, which Williams believes are currently met. These conditions include compliance with the financial covenants and ratios as defined in the agreements (see Note 13), absence of default as defined in the agreements, and continued accuracy of representations and warranties made in the agreements.

At December 31, 2001, Williams had a $2.5 billion shelf registration statement effective with the SEC to issue a variety of debt or equity securities. Subsequent to the issuance of the $1.1 billion of FELINE PACS in January 2002 as discussed below, the remaining availability on the shelf registration is approximately $300 million, because Williams registered both the FELINE PACS and the related common stock to be issued subsequently. In addition, there are other outstanding registration statements filed with the SEC for Northwest Pipeline, Texas Gas Transmission and Transcontinental Gas Pipe Line (each a wholly owned subsidiary of Williams). At March 1, 2002, approximately $450 million of shelf availability remains under these outstanding registration statements and may be used to issue a variety of debt securities. Interest rates and market conditions will affect amounts borrowed, if any, under these arrangements. Williams believes additional financing arrangements, if required, can be obtained on reasonable terms.

Terms of certain borrowing agreements limit transfer of funds to Williams from its subsidiaries. The restrictions have not impeded, nor are they expected to impede, Williams ability to meet its cash requirements in the future.

During 2002, Williams expects to fund capital and investment expenditures, debt payments and working-capital requirements of its continuing operations through (1) cash generated from operations, (2) the use of the available portion of Williams' $700 million bank-credit facility, (3) commercial paper (or the related bank-credit facility), (4) short-term uncommitted bank lines, (5) private borrowings, (6) sale or disposal of existing businesses and/or (7) debt or equity public offerings.

Credit Ratings

Williams maintains certain preferred interest and debt obligations that contain provisions requiring accelerated payment of the related obligations or liquidation of the related assets in the event of specified levels of declines in Williams' credit ratings given by Moody's Investor's Service, Standard & Poor's and Fitch Ratings (rating agencies). Performance by Williams under these terms include potential acceleration of debt payment and redemption of preferred interests totaling $816 million at December 31, 2001.

During the fourth quarter of 2001, Williams announced its intentions to eliminate its exposure to the "ratings trigger" clauses incorporated in the above agreements. At the time of this filing, negotiations had commenced with the respective financial institutions with an objective of completing such changes during the first half of 2002.

At December 31, 2001, Williams' credit ratings were above "trigger" levels by a range of two or more levels. On February 1, 2002, Williams' credit ratings were maintained by each of the rating agencies, although Standard & Poor's placed Williams on "negative watch." On February 27, 2002, Moody's Investor's Service confirmed the investment grade rating of Williams and changed the outlook from stable to negative. On February 28, 2002, Fitch Ratings affirmed its investment grade rating of Williams and also changed the outlook from stable to negative. Standard & Poor's also announced it was maintaining its previous rating from February 1, 2002.

In addition to the factors noted above, Williams' energy marketing and trading business relies upon the investment grade rating of Williams senior unsecured long-term debt to satisfy credit support requirements of many counterparties. If Williams' credit ratings were to decline below investment grade, its ability to participate in energy marketing and trading activity could be significantly limited. Alternate credit support would be required under certain existing agreements and would be necessary to support future transactions. Without an investment grade rating, Williams would be required to fund margining requirements pursuant to industry standard derivative agreements with cash, letters of credit or other negotiable instruments. At December 31, 2001, the total notional amounts that could require such funding, in the event of a credit rating decline of Williams to below investment grade, is approximately $500 million, before consideration of offsetting positions and margin deposits from the same counterparties.

At December 31, 2001, Williams maintained the following credit ratings on its senior unsecured long-term debt, which are considered to be investment grade:

Moody's Investor's Service.................................	Baa2
Standard & Poor's..	BBB
Fitch Ratings..	BBB

Off-Balance Sheet Financing Arrangements and Guarantees of Debt or Other Commitments to Third Parties

During 2000, Williams entered into operating lease agreements with two special purpose entities (SPE's) and provides a financial guarantee to a third SPE. The operating lease agreements are with respect to certain Williams travel center stores, offshore oil and gas pipelines and an onshore gas processing plant (see Note 13), while the guarantee is with respect to gas turbines under construction. The SPE's are not consolidated by Williams since their equity is provided by non-related parties. The sole purpose of these entities is to facilitate financing for construction and acquisition of the related assets. The only assets of the SPE's are the constructed or acquired assets, which serve as collateral for the SPE's liabilities, which are in the form of financing obligations. The lease terms include a five-year base term with a renewal option for an additional five-year term. The funding obligations, if any, of Williams with respect to these entities occurs solely through the lease commitments and the financial guarantee. Williams has an option to purchase the leased assets during the lease terms at amounts approximating the lessor's cost and has an option to acquire the gas turbines at actual cost of construction. For the operating leases, Williams provides residual value guarantees equal to 85 percent of the lessor's cost on the completed travel center stores and 89.9 percent of the lessor's cost, less the present value of actual lease payments, on the offshore oil and gas pipelines and the onshore gas processing plant. The financial guarantee with respect to the gas turbines is also a residual value guarantee equal to a maximum of 89.9 percent of the actual cost of construction. In the event that Williams does not exercise its purchase option, Williams expects the fair market value of the covered assets to substantially reduce its obligation under the residual value guarantees. If these SPE's were consolidated into Williams' Consolidated Balance Sheet at December 31, 2001, they would increase assets and long-term debt by approximately $364 million.

Williams provides a guarantee of approximately $127 million towards project financing of energy assets owned and operated by an entity in which Williams owns an interest of 50 percent. This obligation or guarantee is not consolidated in Williams' balance sheet as Williams does not maintain a controlling interest in the entity and therefore follows equity accounting for its interest. Performance on the guarantees generally would occur upon a failure of payment by the financed entity or certain events of default related to the guarantors. These events of default primarily relate to bankruptcy and/or insolvency of the guarantors. At December 31, 2001, there were no events of default by the guarantors or delinquent payments by the financed entity with respect to the project financings.

Williams is a party to a put agreement arising from its sale of Ferrellgas senior common units in April 2001 (see Note 4) whereby the purchaser's lenders can require Williams to repurchase the units upon certain events of default by the purchaser or the failure or default by the seller (Williams) under any of its debt obligations greater than $60 million. The total outstanding under the put agreement at December 31, 2001 was $99.6 million. Williams' contingent obligation reduces as purchaser's payments are made to the lender. The purchaser's agreement is for a five year term, expiring December 30, 2005. The put agreement represents a contingent liability and is not reflected on Williams' balance sheet. At December 31, 2001, there have been no events of default and the purchaser has performed as required under payment terms with the lender.

For each of the Williams' guarantees discussed above, Williams has currently assessed that its future performance under each of the agreements as less than probable for purposes of SFAS No. 5, "Accounting for Contingencies." This assessment is based on information available at December 31, 2001 affirming there are no events of default on behalf of Williams as a guarantor and none of the related entities are delinquent with respect to the supported obligations.

Williams has agreements to sell, on an ongoing basis, certain of its accounts receivable to qualified special-purpose entities ("QSPE"). Under these agreements, Williams is able to sell up to $450 million of accounts receivables. These QSPEs are not consolidated; however, if these QSPEs were consolidated at December 31, 2001, assets and debt would increase by $420 million.

WCG Separation

Since the initial equity offering by WCG in October 1999, the sources of liquidity for WCG had been separate from Williams' sources of liquidity. The reduction to Williams' stockholders' equity as a result of the separation in April 2001 was approximately $2.0 billion. Williams, with respect to shares of WCG's common stock that Williams retained, has committed to the Internal Revenue Service (IRS) to dispose of all of the WCG shares that it retains as soon as market conditions allow, but in any event not longer than five years after the spinoff. As part of a separation agreement and subject to a favorable ruling by the IRS that such a limitation is not inconsistent with any ruling issued to Williams regarding the tax-free treatment of the spinoff, Williams has agreed not to dispose of the retained WCG shares for three years from the date of distribution and must notify WCG of an intent to dispose of such shares. However, on February 28, 2002, Williams filed with the IRS a request to withdraw its request for a ruling that the agreement between Williams and WCG that Williams would not transfer any retained WCG stock for a three-year period from the spinoff would not be inconsistent with the favorable tax-free treatment ruling issued to Williams. Williams represented in the withdrawal request that it had abandoned its intent to make the lock-up effective, thereby making the ruling request moot. For further discussion of separation agreements and potential tax exposure as a result of the WCG separation, see Note 3 of the Notes to Consolidated Financial Statements.

Additionally, Williams, prior to the spinoff and in an effort to strengthen WCG's capital structure, entered into an agreement under which Williams contributed an outstanding promissory note from WCG of approximately $975 million and certain other assets, including a building under construction and a commitment to complete the construction. In return, Williams received 24.3 million newly issued common shares of WCG.

Williams, prior to the spinoff, provided indirect credit support for $1.4 billion of WCG's Note Trust Notes through a commitment to make available proceeds of a Williams equity issuance or other permitted redemption sources in the event any one of the following were to occur: (1) a WCG default; (2) downgrading of Williams' senior unsecured debt to Ba1 or below by Moody's Investor's Service, BB or below by Standard & Poor's, or BB+ or below by Fitch Ratings if Williams' common stock closing price is below $30.22 for ten consecutive trading days while such downgrade is in effect; or (3) to the extent proceeds from WCG's refinancing or remarketing of the WCG Note Trust Notes prior to March 2004 produces proceeds of less than $1.4 billion.

On March 5, 2002, Williams received the requisite approvals on its consent solicitation to amend the terms of the WCG Note Trust Notes. The amendment, among other things, eliminates acceleration of the Notes due to a WCG bankruptcy or a Williams credit rating downgrade. The amendment also affirms Williams' obligations for all payments due with respect to the WCG Note Trust Notes, which are due March 2004, and allows Williams to fund such payments from any available sources. With the exception of the March and September 2002 interest payments, totaling $115 million, WCG remains indirectly obligated to reimburse Williams for any payments Williams is required to make in connection with the WCG Note Trust Notes.

Williams has provided a guarantee of WCG's obligations under a 1998 transaction in which WCG entered into an operating lease agreement covering a portion of its fiber-optic network. The total cost of the network assets covered by the lease agreement is $750 million. The lease term initially totaled five years and, if renewed, could extend to seven years. WCG has an option to purchase the covered network assets during the lease term at an amount approximating lessor's cost. On March 6, 2002, a representative of WCG notified Williams that WCG intends to issue a notice so as to be able to purchase the assets in the immediate future. As a result of an agreement between Williams and WCG's revolving credit facility lenders, if Williams gains control of the network assets covered by the lease, Williams may be obligated to return the assets to WCG and the obligation of WCG to compensate Williams for such property may be subordinated to the interests of WCG's revolving credit facility lenders and may not mature any earlier than one year after the maturity of WCG's revolving credit facility.

Williams has also provided guarantees on certain performance obligations of WCG totaling approximately $57 million.

In third-quarter 2001, Williams purchased the Williams Technology Center and other ancillary assets (Technology Center) and three corporate aircraft from WCG for $276 million which represents the approximate actual cost of construction of the Williams Technology Center and the acquisition cost of the ancillary assets and aircraft. Williams then entered into long-term lease arrangements under which WCG is the sole lessee of the Technology Center and aircraft (see Note 13). As a result of this transaction, Williams' Consolidated Balance Sheet includes $28.8 million in current accounts and notes receivable and $137.2 million in noncurrent other assets and deferred charges, net of allowance of $103.2 million, relating to amounts due from WCG. Additionally, receivables include amounts due from WCG of approximately $27 million at December 31, 2001 which includes a $21 million deferred payment (net of allowance of $85 million) for services provided to WCG due March 15, 2002. In February 2002, the deferred payment for services provided to WCG was extended to September 15, 2002.

Recent disclosures and announcements by WCG, including WCG's recent announcement that it might seek to reorganize under the U.S. Bankruptcy Code, have resulted in Williams concluding that it is probable that it will not fully realize the $375 million of receivables from WCG at December 31, 2001 nor recover its remaining $25 million investment in WCG common stock. In addition, Williams has determined that it is probable that it will be required to perform under the $2.21 billion of guarantees and payment obligations discussed above. Other events that have affected Williams' assessment include the credit downgrades of WCG, the bankruptcy of a significant competitor announced on January 28, 2002, and public statements by WCG regarding an ongoing comprehensive review of its bank secured credit arrangements. As a result of these factors, Williams, using the best information available at the time and under the circumstances, has developed an estimated range of loss related to its total WCG exposure. Management utilized the assistance of external legal counsel and an external financial and restructuring advisor in making estimates related to its guarantees and payment obligations and ultimate recovery of the contractual amounts receivable from WCG. At this time, management believes that no loss within the range is more probable than another. Accordingly, Williams has recorded the $2.05 billion minimum amount of the range of loss which is reported in the Consolidated Statement of Operations as a $1.84 billion pre-tax charge to discontinued operations and a $213 million pre-tax charge to continuing operations. Williams recognized a related deferred tax benefit in the Consolidated Statement of Operations of $742.5 million ($68.9 million in continuing operations and $673.6 million in discontinued operations). The ultimate amount of tax benefit realized could be different from the deferred tax benefit recorded, as influenced by potential changes in federal income tax laws and the circumstances upon the actual realization of the tax benefits from WCG's balance sheet restructuring program.

The charge to discontinued operations of $1.84 billion includes the minimum amount of the estimated range of loss from performance on $2.21 billion of guarantees and payment obligations and approximately $16 million in expenses. With the exception of the interest on the Note Trust Notes and the expenses, Williams has assumed for purposes of this estimated loss that it will become an unsecured creditor of WCG for all or part of the amounts paid under the guarantees and payment obligations. However, it is probable that Williams will not be able to recover a significant portion of the receivables. The estimated loss from the performance of the guarantees and payment obligations is based on the overall estimate of recoveries on amounts receivable discussed below. Due to the amendment of the WCG Note Trust Notes discussed above, $1.1 billion of the accrued loss will be classified as a long-term liability in the Consolidated Balance Sheet.

The charge to continuing operations of $213 million includes estimated losses from an assessment of the recoverability of carrying amounts of the $106 million deferred payment for services provided to WCG, the $269 million minimum lease payments receivable from WCG, and a remaining $25 million investment in WCG common stock. The $85 million provision on the deferred payment is based on the overall estimate of recoveries on amounts receivable using the same assumptions on collectibility as discussed below. The $103 million provision on the minimum lease payments receivable is based on an estimate of the fair value of the leased assets. The $25 million write-off of the WCG investment is based on management's assessment of realization as a result of WCG's balance sheet restructuring program.

The estimated range of loss assumes that Williams, as a creditor of WCG, will recover only a portion of its claims against WCG. Such claims include a $2.21 billion receivable from performance on guarantees and payment obligations and a $106 million deferred payment for services provided to WCG. With the assistance of external legal counsel and an external financial and restructuring advisor, and considering the best information available at the time and under the circumstances, management developed a range of loss on these receivables with a minimum loss of 80 percent on claims in a bankruptcy of WCG. Estimating the range of loss as a creditor involves making complex judgments and assumptions about uncertain outcomes. The actual loss may ultimately differ from the recorded loss due to changes in numerous factors, which include, but are not limited to, the future demand for telecommunications services and the state of the telecommunications industry, WCG's individual performance, and the nature of the restructuring of WCG's balance sheet. There could be additional losses recognized in the future, a portion of which may be reflected as discontinued operations.

The minimum amount of loss in the range is estimated based on recoveries from a successful reorganization process under Chapter 11 of the U.S. Bankruptcy Code. Recoveries after a successful reorganization process depend, among other things, on the impact of a bankruptcy on WCG's financial performance and WCG's ability to continue uninterrupted business services to its customers and to maintain relationships with vendors. To estimate recoveries of the unsecured creditors, Williams estimated an enterprise value of WCG using a present value analysis and reduced the enterprise value by the level of secured debt which may exist in WCG's restructured balance sheet. In its estimate of WCG's enterprise value, Williams considered a range of cash flow estimates based on information from WCG and from other external sources. Future cash flow projections are valued using discount rates ranging from 17 percent to 25 percent. The range of cash flows is based on different scenarios related to the growth, if any, of WCG's revenues and the impact that a bankruptcy may have on revenue growth. The range of discount rates considers WCG's assumed restructured capital structure and the market return that equity investors may require to invest in a telecommunications business operating in the current distressed industry environment. The range of loss also considers recoveries based on transaction values from recent telecommunications restructurings and from a liquidation of WCG's assets.

Should WCG go into bankruptcy under Chapter 7 of the U.S. Bankruptcy Code, recoveries under a liquidation include factors such as the nature of WCG's assets, the value of operating assets in a distressed telecommunications market, the cost of liquidation, operating losses during the period of liquidation, the length of liquidation period and claims of creditors superior to those of Williams' unsecured claims.

Significant items reflected as discontinued operations in the Consolidated Statement of Cash Flows include the following:

- In 2000, WCG issued $1 billion in long-term debt obligations consisting of $575 million in 11.7 percent notes due 2008 and $425 million in 11.875 percent notes due 2010. In October 1999, WCG completed an initial public equity offering, private equity offerings and public debt offerings that yielded total net proceeds of approximately $3.5 billion. The initial public equity offering yielded net proceeds of approximately $738 million (see Note 3). In concurrent investments by SBC Communications Inc., Intel Corporation and Telefonos de Mexico, additional shares of common stock were privately sold for proceeds of $738.5 million. Concurrent with these equity transactions, WCG issued high-yield public debt of approximately $2 billion. Proceeds from the 1999 equity and debt transactions were used to repay WCG's 1999 borrowings under an interim short-term bank-credit facility and the $1.05 billion bank-credit agreement. The remaining proceeds from the 1999 transactions and the 2000 debt proceeds were used to fund 2000 WCG's operating losses, continued construction of WCG's national fiber-optic network and other capital and investment expansion opportunities. During 2000, WCG received net proceeds of approximately $240.5 million from the issuance of five million shares of 6.75 percent redeemable cumulative preferred stock.

- Capital expenditures of WCG, primarily for the construction of the fiber-optic network, were $3.4 billion in 2000, $1.7 billion in 1999 and $304 million in 1998.

- In 1999, WCG paid $265 million in cash to increase its investment in ATL (a Brazilian telecommunications business).

OPERATING ACTIVITIES

Cash provided by continuing operating activities was: 2001 -- $1.8 billion; 2000 -- $594 million; and 1999 -- $1.5 billion. The 2001 $517.1 million decrease in margin deposits is due primarily to lower deposits required by counterparties related to trading activities at Energy Marketing & Trading. The 2001 $201.4 million increase in other current assets is due primarily to increases associated with current derivative assets. The 2001 increase in other assets and deferred charges of $455.0 million is due primarily to the increases associated with noncurrent derivative assets and the minimum lease payments receivable (net of an allowance for doubtful accounts) due from WCG related to the long-term lease arrangement with WCG (see Note 3). The increase in derivative assets reflects the impact of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," which requires these contracts to be recorded at fair value.

FINANCING ACTIVITIES

Net cash provided by financing activities of continuing operations was: 2001 -- $2.0 billion; 2000 -- $2.0 billion; and 1999 -- $880 million. Long-term debt proceeds, net of principal payments, were $1.9 billion, $235 million and $682 million, during 2001, 2000 and 1999, respectively. Notes payable payments, net of notes payable proceeds, were $801 million in 2001. Notes payable proceeds, net of notes payable payments were $1.5 billion and $210 million during 2000 and 1999, respectively. The increase in net new borrowings during 2001, 2000 and 1999 reflects borrowings to fund capital expenditures, investments and acquisitions of businesses.

The proceeds from issuance of Williams common stock in 2001 reflect $1.3 billion in net proceeds from approximately 38 million shares of common stock issued by Williams in January 2001 in a public offering at $36.125 per share. Additionally, the proceeds from issuance of Williams common stock in 2001, 2000 and 1999 reflect exercise of stock options under the plans providing for common-stock-based awards to employees and to non-employee directors.

Dividends paid on common stock increased $75.2 million in 2001 reflecting an increase in the number of shares outstanding and an increase in the per share dividends. The number of shares increased due primarily to the 38 million shares issued in January 2001 and the 29.6 million shares issued in the Barrett acquisition. Third-quarter 2001 and fourth-quarter 2001 dividends increased to 18 cents per share and 20 cents per share, respectively, up from the quarterly dividend of 15 cents per share in 2000.

Proceeds from sale of limited partners units of consolidated partnership reflect an initial public offering of Williams Energy Partners L.P. (WEP), a wholly owned partnership which owns and operates a diversified portfolio of energy assets, of approximately 4.6 million common units at $21.50 per unit for net proceeds of approximately $92 million. The initial public offering represents 40 percent of the units, and Williams retained a 60 percent interest in the partnership, including its general partner interest.

In December 2001, Williams received net proceeds of $95.3 million from sale of a non-controlling preferred interest in Piceance Production Holdings LLC to an outside investor (see Note 14). During 2000, Williams received net proceeds totaling $546.8 million from the sale of a limited liability company member interest to an outside investor (see Note 14).

In April 2001, Williams redeemed the Williams obligated mandatorily redeemable preferred securities of Trust holding only Williams indentures for $194 million. Proceeds from the sale of the Ferrellgas senior common units held by Williams were used for this redemption. In 1999, Williams received proceeds of $175 million from the sale of the Williams obligated mandatorily redeemable preferred securities.

In connection with the Barrett acquisition, Williams' Consolidated Balance Sheet includes $150 million of 7.55 percent notes due 2007, which are debt obligations guaranteed by Williams (parent). For further discussion of the Barrett Resources Corporation acquisition, see Note 2.

Long-term debt at December 31, 2001 was $9.5 billion, compared with $6.8 billion at December 31, 2000 and $7.2 billion at December 31, 1999. At December 31, 2001 and 2000, $844 million and $800 million, respectively, of current debt obligations were classified as noncurrent obligations based on Williams' intent and ability to refinance on a long-term basis. The 2001 increase in long-term debt is due primarily to the $1.1 billion of senior unsecured debt securities issued in January 2001 and the $1.5 billion of long-term debt securities issued in August 2001 primarily to replace $1.2 billion borrowed under a $1.5 billion short-term agreement originated in June 2001 related to the cash portion of the Barrett acquisition. The long-term debt to debt-plus-equity ratio (including consolidated WCG debt for 2000 and 1999) was 61.1 percent at December 31, 2001, compared to 63.7 percent and 62.3 percent at December 31, 2000 and 1999, respectively. If short-term notes payable and long-term debt due within one year were included in the calculations, these ratios would be 66.4 percent, 70.5 percent and 65.9, respectively. Additionally, the long-term debt to debt plus equity as calculated for covenants under certain debt agreements was 61.5 percent at December 31, 2001.

In January 2002, Williams issued 44 million publicly traded units, more commonly known as FELINE PACS, that include a senior debt security and an equity purchase contract. The debt has a term of five years, and the equity purchase contract will require the company to deliver Williams common stock to holders after three years based on a previously agreed rate. Net proceeds from this issuance were approximately $1.1 billion (see Note 23).

INVESTING ACTIVITIES

Net cash used by investing activities of continuing operations was: 2001 -- $3.5 billion; 2000 -- $2.3 billion; and 1999 -- $2.0 billion. Capital expenditures of Energy Marketing & Trading, primarily to construct power generation plants, were $104 million in 2001, $64 million in 2000 and $83 million in 1999. Capital expenditures of Energy Services, primarily to carry out drilling programs and acquire, expand and modernize gathering and processing facilities, terminals and refineries, were $931 million in 2001, $813 million in 2000 and $1.3 billion in 1999. Capital expenditures of Gas Pipeline, primarily to expand deliverability into the east and west coast markets and upgrade current facilities, were $855 million in 2001, $512 million in 2000 and $360 million in 1999. Budgeted capital expenditures and investments for continuing operations for 2002 are estimated to be approximately $3.2 billion, including expansion and modernization of pipeline systems, gathering and processing facilities, refineries and international investment activities. Williams stated in December 2001 that it had reduced its planned 2002 capital expenditure program in an effort to maintain its investment grade rating. Additional reductions may be necessary to maintain its investment grade rating, however, Williams will evaluate other alternatives in order to maintain their capital expenditure program including sales of additional assets.

On June 11, 2001, Williams acquired 50 percent of Barrett's outstanding common stock in a cash tender offer of $73 per share for a total of approximately $1.2 billion. On August 2, 2001, Williams completed the acquisition of Barrett by issuing 29.6 million shares of Williams common stock in exchange for the remaining Barrett shares.

The increase in investments is due primarily to the development of Williams' joint interest in the Gulfstream project. The increase in proceeds received from disposition of investments and other assets reflects Williams' sale of the Ferrellgas senior common units to an affiliate of Ferrellgas for proceeds of $199 million in April 2001 and the sale of certain convenience stores for approximately $150 million in May 2001. The purchase of assets subsequently leased to seller reflects Williams' purchase of the Williams Technology Center, other ancillary assets and three corporate aircraft for $276 million.

In October 2000, Williams acquired various energy-related operations in Canada for approximately $540 million. Included in the purchase were interests in several NGL extraction and fractionation plants, NGL transportation pipeline and storage facilities, and a natural gas processing plant.

During 1999, Williams purchased a business which includes a petrochemical plant and natural gas liquids transportation, storage and other facilities for $163 million in cash. Also during 1999, Williams made various cash investments and advances totaling $347 million including a $75 million equity investment in and a $75 million loan to AB Mazeikiu Nafta, Lithuania's national oil company, $78 million in various natural gas and petroleum products pipeline joint ventures, and other joint ventures and investments. In addition, Williams made $139 million of investments in the Alliance natural gas pipeline and processing plant during 1999 of which $93.5 million was financed with a note payable which was paid in 2000. In December 1999, Williams sold its retail propane business to Ferrellgas for $268.7 million in cash and $175 million in senior common units of Ferrellgas.

COMMITMENTS

The table below summarizes some of the more significant contractual obligations and commitments by period. This table does not include obligations related to guarantees or payment obligations related to WCG (see Note 3).

	2002	2003	2004	2005	2006	THEREAFTER	TOTAL
				(MILLIONS)			
Notes payable	$1,425	$ --	$ --	$ --	$ --	$ --	$ 1,425
Long-term debt, including current portion	1,037	732	1,562	282	1,156	5,759	10,528
Operating leases	82	58	47	37	29	176	429
Preferred interest in consolidated subsidiaries(1)	200	135	--	560	100	--	995
Fuel conversion and other service contracts(2)	344	420	443	446	449	5,926	8,028
Total	$3,088	$1,345	$2,052	$1,325	$1,734	$11,861	$21,405

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(1) Amount relates to that invested by an outside investor for which the end of the initial priority return period is shown.

(2) Energy Marketing & Trading has entered into certain contracts giving Williams the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are either currently in operation or are to be constructed at various locations throughout the continental United States. These contracts are included at fair value within energy risk management and trading assets and liabilities.

Additionally, at December 31, 2001, commitments for construction and acquisition of property, plant and equipment are approximately $771 million. At December 31, 2001, commitments for additional investments in Gulfstream Pipeline, LLC, certain international cost investments and advances to Longhorn Partners Pipeline, L.P. are $233 million.

RECENTLY ISSUED ACCOUNTING STANDARDS AND POTENTIAL NEW ACCOUNTING STANDARDS

See Note 1 for a discussion of SFAS No. 141, "Business Combinations," SFAS No. 142, "Goodwill and Other Intangible Assets," SFAS No. 143, "Accounting for Asset Retirement Obligations" and SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

The accounting for Energy Marketing & Trading's energy-related contracts, which include contracts such as transportation, storage, load servicing and tolling agreements, requires Williams to assess whether certain of these contracts are executory service arrangements or leases pursuant to SFAS No. 13, "Accounting for Leases." There currently is not extensive authoritative guidance for determining when an arrangement is a lease or an executory service arrangement. As a result, Williams assesses each of its energy-related contracts and makes the determination based on the substance of each contract focusing on factors such as physical and operational control of the related asset, risks and rewards of owning, operating and maintaining the related asset and other contractual terms. The Emerging Issues Task Force of the Financial Accounting Standards Board is in the preliminary stage of addressing Issue No. 01-8, "Determining Whether an Arrangement is a Lease," and has assigned the Issue to a Working Group for further consideration. As the Issue is in the preliminary phase, the outcome and related impact to Williams is not yet determinable.

EFFECTS OF INFLATION

Williams' cost increases in recent years have benefited from relatively low inflation rates during that time. Approximately 43 percent of Williams' property, plant and equipment is at Gas Pipeline and approximately 55 percent is at Energy Services. Approximately 87 percent of Gas Pipeline's and 60 percent of Energy Services' property, plant and equipment has been acquired or constructed since 1995, a period of relatively low inflation. Approximately 17 percent of Energy Services' increase was the result of the 2001 Barrett acquisition. Gas Pipeline is subject to regulation, which limits recovery to historical cost. While amounts in excess of historical cost are not recoverable under current FERC practices, Williams believes it will be allowed to recover and earn a return based on increased actual cost incurred to replace existing assets. Cost-based regulation along with competition and other market factors may limit the ability to recover such increased costs. Within Energy Services, operating costs are influenced to a greater extent by specific price changes in oil and gas and related commodities than by changes in general inflation. Crude, refined product, natural gas and natural gas liquids prices are particularly sensitive to OPEC production levels and/or the market perceptions concerning the supply and demand balance in the near future.

ENVIRONMENTAL

Williams is a participant in certain environmental activities in various stages involving assessment studies, cleanup operations and/or remedial processes. The sites, some of which are not currently owned by Williams (see Note 19), are being monitored by Williams, other potentially responsible parties, the U.S. Environmental Protection Agency (EPA), or other governmental authorities in a coordinated effort. In addition, Williams maintains an active monitoring program for its continued remediation and cleanup of certain sites connected with its refined products pipeline activities. Williams has both joint and several liability in some of these activities and sole responsibility in others. Current estimates of the most likely costs of such cleanup activities are approximately $98 million, all of which is accrued at December 31, 2001. Williams expects to seek recovery of approximately $42 million of the accrued costs through future natural gas transmission rates. Williams will fund these costs from operations and/or available bank-credit facilities. Estimates of the most likely costs of cleanup are generally based on completed assessment studies, preliminary results of studies or other similar cleanup operations. At December 31, 2001, certain assessment studies were still in process for which the ultimate outcome may yield significantly different estimates of most likely costs. Therefore, the actual costs incurred will depend on the final amount, type and extent of contamination discovered at these sites, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

Williams is subject to the federal Clean Air Act and to the federal Clean Air Act Amendments of 1990 which require the EPA to issue new regulations. Williams is also subject to certain states' regulations. In September 1998, the EPA promulgated rules designed to mitigate the migration of ground-level ozone in certain states. Williams estimates that capital expenditures necessary to install emission control devices over the next five years to comply with rules will be between $186 million and $206 million. The actual costs incurred will depend on the final implementation plans developed by each state to comply with these regulations. In December 1999, standards promulgated by the EPA for tailpipe emissions and the content of sulfur in gasoline were announced. Williams estimates that capital expenditures necessary to bring its two refineries into compliance over the next five years will be approximately $385 million. The actual costs incurred will depend on the final implementation plans. In addition to the above mentioned capital expenditures pertaining to the Clean Air Act and amendments, estimated future capital expenditures as of December 31, 2001, for various compliance issues across the company are approximately $202 million.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from Williams' pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period July 1, 1998 through July 2, 2001. In November 2001, Williams furnished its response.

In July 1999, Transco received a letter stating that the U.S. Department of Justice (DOJ), at the request of the EPA, intends to file a civil action against Transco arising from its waste management practices at Transco's compressor stations and metering stations in 11 states from Texas to New Jersey. Transco, the EPA and the DOJ agreed to settle this matter by signing a Consent Decree that provides for a civil penalty of $1.4 million.

Williams Field Services (WFS), an Energy Services subsidiary, received a Notice of Violation (NOV) from the EPA in February 2000. WFS received a contemporaneous letter from the DOJ indicating that the DOJ will also be involved in the matter. The NOV alleged violations of the Clean Air Act at a gas processing plant. WFS, the EPA and the DOJ agreed to settle this matter for a penalty of $850,000. In the course of investigating this matter, WFS discovered a similar potential violation at the plant and disclosed it to the EPA and the DOJ. In December 2001, the EPA, the DOJ and WFS agreed to settle this self-reported matter by signing a Consent Decree that provides for a penalty of $950,000.

OTHER

In January, 2002, Williams announced the goal to reduce the company's annual operating expenses based on the company's current cost structure by $50 million, effective 2003. Management is evaluating its organizational structure to determine effective and efficient ways to align services to meet Williams' current business requirements as an energy-only company. In conjunction with this goal, Williams is offering an enhanced-benefit early retirement option to certain employee groups. The potential impact to 2002 expense, assuming election by 100 percent of those eligible for the early retirement option, would be approximately $80 million. Williams does not anticipate that all eligible employees will elect the option. Additionally, Williams also will offer severance and redeployment services to employees whose positions are eliminated as a result of the organizational changes.

Williams has also announced plans to sell its midwest petroleum products pipeline and on-system terminals. A potential buyer would be Williams Energy Partners L.P., a consolidated entity.

ITEM 7A. MARKET RISK DISCLOSURES

Interest Rate Risk

Williams' current interest rate risk exposure is related primarily to its debt portfolio and its energy risk management and trading portfolio. In 2000, Williams' interest rate exposure also related to an investment in Ferrellgas Partners L.P. senior common units and Williams obligated mandatorily redeemable preferred securities of Trust.

Williams' interest rate risk exposure resulting from its debt portfolio is influenced by short-term rates, primarily LIBOR-based borrowings from commercial banks and the issuance of commercial paper, and long-term U.S. Treasury rates. To mitigate the impact of fluctuations in interest rates, Williams targets to maintain a significant portion of its debt portfolio in fixed rate debt. Williams has also utilized interest-rate swaps to change the ratio of its fixed and variable rate debt portfolio based on management's assessment of future interest rates, volatility of the yield curve and Williams' ability to access the capital markets in a timely manner. Williams periodically enters into interest-rate forward contracts to establish an effective borrowing rate for anticipated long-term debt issuances. The maturity of Williams' long-term debt portfolio is partially influenced by the expected life of its operating assets.

At December 31, 2001 and 2000, the amount of Williams' fixed and variable rate debt was at targeted levels. Williams has traditionally maintained an investment grade credit rating as one aspect of managing its interest rate risk. In order to fund its 2002 capital expenditure plan, Williams will need to access various sources of liquidity, which will likely include traditional borrowing and leasing markets.

Williams also has interest rate risk in long-dated energy-related contracts included in its energy risk management and trading portfolio. The value of these transactions can fluctuate daily based on movements in the underlying interest rate curves used to assign value to the transactions. Williams strives to mitigate the associated interest rate risk from the value of these transactions by fixing the underlying interest rate inherent in the energy risk management and trading portfolio. During 2001, Williams began actively managing this exposure as a component of its targeted levels of fixed to floating obligations. Williams uses both floating to fixed interest rate swaps and other derivative transactions to manage this variable rate exposure.

The tables on the following page provide information as of December 31, 2001 and 2000, about Williams' interest rate risk sensitive instruments. For investment in Ferrellgas Partners L.P. senior common units, notes payable, long-term debt and Williams obligated mandatorily redeemable preferred securities of Trust, the table presents principal cash flows and weighted-average interest rates by expected maturity dates. For interest-rate swaps, the table presents notional amounts and weighted-average interest rates by contractual maturity dates. Notional amounts are used to calculate the contractual cash flows to be exchanged under the interest-rate swaps.

	2002	2003	2004	2005	2006	THEREAFTER	TOTAL	FAIR VALUE DECEMBER 31, 2001
				(DOLLARS IN MILLIONS)				
Notes payable...........	$1,425	$ --	$ --	$ --	$ --	$ --	$1,425	$1,425
Interest rate...........	3.3%							
Long-term debt, including current portion:								
Fixed rate............	$ 833	$330	$621	$282	$1,156	$5,759	$8,981	$9,164
Interest rate.........	7.2%	7.3%	7.3%	7.3%	7.4%	7.6%		
Variable rate.........	$ 204	$402	$941	$ --	$ --	$ --	$1,547	$1,547
Interest rate(1)								
Interest rate swaps(2)								

	2001	2002	2003	2004	2005	THEREAFTER	TOTAL	FAIR VALUE DECEMBER 31, 2000
				(DOLLARS IN MILLIONS)				
Assets:								
Investment -- Ferrellgas Partners L.P. senior common units..........	$ --	$ 194	$ --	$ --	$ --	$ --	$ 194	$ 194
Fixed rate............	10.0%	10.0%	--	--	--	--		
Liabilities:								
Notes payable.........	$2,037	$ --	$ --	$ --	$ --	$ --	$2,037	$2,037
Interest rate.........	7.2%	--	--	--	--	--		
Long-term debt, including current portion:								
Fixed rate.........	$1,115	$1,032	$306	$356	$254	$2,972	$6,035	$6,092
Interest rate......	7.1%	7.2%	7.3%	7.3%	7.3%	7.6%		
Variable rate......	$ 524	$ 154	$402	$201	$350	$ 799	$2,430	$2,430
Interest rate(1)								
Williams obligated mandatorily redeemable preferred securities of Trust..............	$ --	$ 190	$ --	$ --	$ --	$ --	$ 190	$ 192
Fixed rate..............	7.9%	7.9%	--	--	--	--		
Interest rate swaps:								
Pay variable/receive fixed.................	$ 461	$ --	$ --	$ --	$ --	$ --	$ 461	$ (3)
Pay rate(3)								
Receive rate............	6.0%	--	--	--	--	--		
Pay fixed/receive variable..............	$ 53	$ 59	$ 65	$ 72	$ 79	$ 133	$ 461	$ (30)
Pay rate................	7.8%	8.0%	8.0%	8.0%	8.0%	8.0%		
Receive rate(3)								

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(1) 2001 -- Weighted average interest rate is LIBOR plus one percent for all years; 2000 -- Weighted average interest rate is LIBOR plus .70 percent for all years.

(2) The interest rate swaps which are outstanding at December 31, 2001 are reflected at fair value within energy risk management and trading assets and liabilities in the Consolidated Balance Sheet as these swaps are entered into to mitigate the interest rate risk inherent in the energy risk management and trading portfolio. Notional amounts total approximately $1 billion at December 31, 2001.

(3) LIBOR

COMMODITY PRICE RISK

Energy Marketing & Trading has trading operations that incur commodity price risk as a consequence of providing price-risk management services to third-party customers. The most significant exposure to commodity price-risk is associated with the natural gas and electricity markets in the United States. This exposure is primarily within the portfolio of transportation, storage, full-requirements, load serving and power tolling contracts. Energy Marketing & Trading also has commodity price-risk exposure to crude oil, refined products, electricity, natural gas and natural gas liquids markets in the United States and the natural gas markets in Canada through other energy contracts such as forward, futures, options, swaps, and purchase and sale contracts. These energy and energy-related contracts are valued at fair value and unrealized gains and losses from changes in fair value are recognized in income. These energy and energy-related contracts are subject to risk from changes in energy commodity market prices, volatility and correlation of those commodity prices, the portfolio position of its contracts, the liquidity of the market in which the contract is transacted and changes in interest rates. Energy Marketing & Trading actively seeks to diversify its portfolio in managing the commodity price risk in the transactions that it executes in various markets and regions by executing offsetting contracts to manage this risk in accordance with parameters established in its trading policy. Energy Marketing & Trading's Risk Control Group monitors compliance with the established trading policy and measures the risk associated with the trading portfolio.

Energy Marketing & Trading measures the market risk in its trading portfolio utilizing a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of its trading operations. At December 31, 2001 and 2000, the value at risk for the trading operations was $92.7 million and $90.1 million, respectively. As supplemental quantitative information to further understand the general risk levels of the trading portfolio, the average of the actual monthly changes in the fair value of the trading portfolio for 2001 was an increase of $120 million. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the trading portfolio. Energy Marketing & Trading's value-at-risk model includes all financial instruments and physical positions and commitments in its trading portfolio and assumes that as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in the fair value of the trading portfolio will not exceed the value at risk. The value-at-risk model uses historical simulations to estimate hypothetical movements in future market prices assuming normal market conditions based upon historical market prices. Value at risk does not consider that changing the energy risk management and trading portfolio in response to market conditions could affect market prices and could take longer to execute than the one-day holding period assumed in the value-at-risk model. Through risk management practices and policies, Energy Marketing & Trading was able to minimize the increase in value at risk while growing the net energy risk management and trading assets 179 percent. This was accomplished primarily through the execution of offsetting contracts, which has the effect of mitigating the commodity price risk exposure within the portfolio of energy and energy-related contracts.

FOREIGN CURRENCY RISK

Williams has international investments that could affect the financial results if the investments incur a permanent decline in value as a result of changes in foreign currency exchange rates and the economic conditions in foreign countries.

International investments accounted for under the cost method totaled $143 million and $144 million at December 31, 2001 and 2000, respectively. The fair value of these investments is deemed to approximate their carrying amount as the investments are primarily in non-publicly traded companies for which it is not practicable to estimate the fair value of these investments. Williams continues to believe that it can realize the carrying value of these investments considering the status of the operations of the companies underlying these investments. If a 20 percent change occurred in the value of the underlying currencies of these investments against the U.S. dollar, the fair value of these investments at December 31, 2001, could change by approximately $29 million assuming a direct correlation between the currency fluctuation and the value of the investments.

The net assets of foreign operations which are consolidated are located primarily in Canada and approximate 11 percent of Williams' net assets at December 31, 2001. These foreign operations, whose functional currency is the local currency, do not have significant transactions or financial instruments denominated in other currencies. However, these investments do have the potential to impact Williams' financial position, due to fluctuations in these local currencies arising from the process of re-measuring the local functional currency into the U.S. dollar. As an example, a 20 percent change in the respective functional currencies against the U.S. dollar could have changed stockholders' equity by approximately $155 million at December 31, 2001.

Williams historically has not utilized derivatives or other financial instruments to hedge the risk associated with the movement in foreign currencies with the exception of a Canadian dollar-denominated note receivable (see Note 18). However, Williams evaluates currency fluctuations and will consider the use of derivative financial instruments or employment of other investment alternatives if cash flows or investment returns so warrant.

EQUITY PRICE RISK

Equity price risk primarily arises from investments in publicly traded energy-related companies. The investments in the energy-related companies are carried at fair value and totaled approximately $8 million and $22 million at December 31, 2001 and 2000, respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT AUDITORS

To the Stockholders of
The Williams Companies, Inc.

We have audited the accompanying consolidated balance sheet of The Williams Companies, Inc. as of December 31, 2001 and 2000, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2001. Our audits also included the financial statement schedule listed in the Index at Item 14(a). 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 with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of The Williams Companies, Inc. at December 31, 2001 and 2000, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

ERNST & YOUNG LLP

Tulsa, Oklahoma
March 6, 2002

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF OPERATIONS

(MILLIONS, EXCEPT PER-SHARE AMOUNTS)	YEARS ENDED DECEMBER 31, 2001	2000	1999
Revenues:			
Energy Marketing & Trading	$ 1,871.8	$1,572.6	$ 662.3
Gas Pipeline	1,748.8	1,879.2	1,822.6
Energy Services*	8,155.1	6,591.5	4,324.4
Other	76.3	66.8	65.4
Intercompany eliminations	(817.3)	(518.2)	(245.3)
Total revenues	11,034.7	9,591.9	6,629.4
Segment costs and expenses:			
Costs and operating expenses*	7,384.6	6,441.8	4,730.4
Selling, general and administrative expenses	934.9	771.5	686.2
Impairment of soda ash mining facility	170.0	--	--
Other (income) expense -- net	(29.1)	75.4	(30.7)
Total segment costs and expenses	8,460.4	7,288.7	5,385.9
General corporate expenses	124.3	97.2	76.9
Operating income:			
Energy Marketing & Trading	1,296.1	1,005.5	104.5
Gas Pipeline	673.8	714.5	688.3
Energy Services	591.5	571.7	439.6
Other	12.9	11.5	11.1
General corporate expenses	(124.3)	(97.2)	(76.9)
Total operating income	2,450.0	2,206.0	1,166.6
Interest accrued	(786.8)	(708.5)	(590.3)
Interest capitalized	40.0	49.4	34.6
Investing income (loss)	(198.4)	106.1	25.1
Preferred returns and minority interest in income of consolidated subsidiaries	(67.5)	(58.0)	(38.2)
Other income (expense) -- net	28.3	.3	(12.1)
Income from continuing operations before income taxes and extraordinary gain	1,465.6	1,595.3	585.7
Provision for income taxes	630.2	629.9	230.8
Income from continuing operations	835.4	965.4	354.9
Loss from discontinued operations	(1,313.1)	(441.1)	(198.7)
Income (loss) before extraordinary gain	(477.7)	524.3	156.2
Extraordinary gain	--	--	65.2
Net income (loss)	(477.7)	524.3	221.4
Preferred stock dividends	--	--	2.8
Income (loss) applicable to common stock	$ (477.7)	$ 524.3	$ 218.6
Basic earnings (loss) per common share:			
Income from continuing operations	$ 1.68	$ 2.17	$ .81
Loss from discontinued operations	(2.64)	(.99)	(.46)
Income (loss) before extraordinary gain	(.96)	1.18	.35
Extraordinary gain	--	--	.15
Net income (loss)	$ (.96)	$ 1.18	$ .50
Diluted earnings (loss) per common share:			
Income from continuing operations	$ 1.67	$ 2.15	$ .79
Loss from discontinued operations	(2.62)	(.98)	(.44)
Income (loss) before extraordinary gain	(.95)	1.17	.35
Extraordinary gain	--	--	.15
Net income (loss)	$ (.95)	$ 1.17	$ .50

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* Includes consumer excise taxes of $308.9 million, $287.6 million and $229.0 million in 2001, 2000 and 1999, respectively.

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED BALANCE SHEET

(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS)	DECEMBER 31, 2001	DECEMBER 31, 2000
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,301.1	$ 996.8
Accounts and notes receivable less allowance of $256.6 ($9.8 in 2000)	3,133.9	3,357.3
Inventories	813.8	848.4
Energy risk management and trading assets	6,514.1	7,879.8
Margin deposits	213.8	730.9
Deferred income taxes	440.6	64.9
Other	520.7	319.3
Total current assets	12,938.0	14,197.4
Net assets of discontinued operations	--	2,290.2
Investments	1,563.1	1,368.6
Property, plant and equipment -- net	17,719.2	14,205.9
Energy risk management and trading assets	4,209.4	1,831.1
Goodwill and other intangible assets, net	1,180.6	42.5
Other assets and deferred charges less allowance of $103.2 (none in 2000)	1,295.9	840.9
Total assets	$38,906.2	$34,776.6
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Notes payable	$ 1,424.5	$ 2,036.7
Accounts payable	2,896.7	3,088.0
Accrued liabilities	1,965.2	1,387.4
Energy risk management and trading liabilities	5,525.7	7,597.3
Guarantees and payment obligations related to Williams Communications Group, Inc.	645.6	--
Long-term debt due within one year	1,036.8	1,634.1
Total current liabilities	13,494.5	15,743.5
Long-term debt	9,500.7	6,830.5
Deferred income taxes	3,689.9	2,863.9
Energy risk management and trading liabilities	2,936.6	1,302.8
Guarantees and payment obligations related to Williams Communications Group, Inc.	1,120.0	--
Other liabilities and deferred income	943.1	978.0
Contingent liabilities and commitments (Note 19)		
Minority interests in consolidated subsidiaries	201.0	98.1
Preferred interests in consolidated subsidiaries	976.4	877.9
Williams obligated mandatorily redeemable preferred securities of Trust holding only Williams indentures	--	189.9
Stockholders' equity:		
Preferred stock, $1 per share, 30 million shares authorized	--	--
Common stock, $1 per share par value, 960 million shares authorized, 518.9 million issued in 2001, 447.9 million issued in 2000	518.9	447.9
Capital in excess of par value	5,085.1	2,473.9
Retained earnings	199.6	3,065.7
Accumulated other comprehensive income	345.1	28.2
Other	(65.0)	(81.2)
	6,083.7	5,934.5
Less treasury stock (at cost), 3.4 million shares of common stock in 2001 and 3.6 million in 2000	(39.7)	(42.5)
Total stockholders' equity	6,044.0	5,892.0
Total liabilities and stockholders' equity	$38,906.2	$34,776.6

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS)	PREFERRED STOCK	COMMON STOCK	CAPITAL IN EXCESS OF PAR VALUE	RETAINED EARNINGS	ACCUMULATED OTHER COMPREHENSIVE INCOME	OTHER	TREASURY STOCK	TOTAL
BALANCE, DECEMBER 31, 1998..........	$ 102.2	$432.3	$ 982.4	$ 2,849.5	$ 16.7	$(78.5)	$(47.2)	$ 4,257.4
Comprehensive income:								
Net income -- 1999................	--	--	--	221.4	--	--	--	221.4
Other comprehensive income:								
Unrealized appreciation on marketable equity securities....................	--	--	--	--	104.2	--	--	104.2
Foreign currency translation adjustments...................	--	--	--	--	(18.0)	--	--	(18.0)
Total other comprehensive income..........................								86.2
Total comprehensive income..........								307.6
Cash dividends --								
Common stock ($.60 per share).....	--	--	--	(260.9)	--	--	--	(260.9)
$3.50 preferred stock ($2.04 per share)..........................	--	--	--	(2.8)	--	--	--	(2.8)
Stockholders' notes issued..........	--	--	--	--	--	(9.7)	--	(9.7)
Stockholders' notes repaid..........	--	--	--	--	--	3.3	--	3.3
Conversion of preferred stock - 1.8 million shares....................	(102.2)	8.4	93.8	--	--	--	--	--
Issuance of equity of consolidated subsidiary........................	--	--	1,170.2	--	(3.4)	--	--	1,166.8
Stock award transactions (including 4.0 million common shares)........	--	3.8	78.7	--	--	.4	2.1	85.0
Tax benefit of stock-based awards...	--	--	31.6	--	--	--	--	31.6
ESOP loan repayment.................	--	--	--	--	--	6.9	--	6.9
BALANCE, DECEMBER 31, 1999..........	--	444.5	2,356.7	2,807.2	99.5	(77.6)	(45.1)	5,585.2
Comprehensive income:								
Net income -- 2000................	--	--	--	524.3	--	--	--	524.3
Other comprehensive loss:								
Net unrealized depreciation on marketable equity securities....................	--	--	--	--	(47.4)	--	--	(47.4)
Foreign currency translation adjustments...................	--	--	--	--	(23.9)	--	--	(23.9)
Total other comprehensive loss....								(71.3)
Total comprehensive income..........								453.0
Cash dividends -- ($.60 per share)...........................	--	--	--	(265.8)	--	--	--	(265.8)
Stockholders' notes issued..........	--	--	--	--	--	(18.0)	--	(18.0)
Stockholders' notes repaid..........	--	--	--	--	--	6.6	--	6.6
Stock award transactions (including 3.6 million common shares)........	--	3.4	88.3	--	--	.3	2.6	94.6
Tax benefit of stock-based awards...	--	--	25.6	--	--	--	--	25.6
ESOP loan repayment.................	--	--	--	--	--	7.5	--	7.5
Other...............................	--	--	3.3	--	--	--	--	3.3
BALANCE, DECEMBER 31, 2000..........	--	447.9	2,473.9	3,065.7	28.2	(81.2)	(42.5)	5,892.0
Comprehensive loss:								
Net loss -- 2001..................	--	--	--	(477.7)	--	--	--	(477.7)
Other comprehensive income:								
Net unrealized gains on cash flow hedges..................	--	--	--	--	370.2	--	--	370.2
Net unrealized depreciation on marketable equity securities....................	--	--	--	--	(35.3)	--	--	(35.3)
Foreign currency translation adjustments...................	--	--	--	--	(37.1)	--	--	(37.1)
Minimum pension liability adjustment....................	--	--	--	--	(2.2)	--	--	(2.2)
Total other comprehensive income..........................								295.6
Total comprehensive loss...........								(182.1)
Issuance of common stock (38 million shares)...........................	--	38.0	1,295.4	--	--	--	--	1,333.4
Issuance of common stock for acquisition of business (29.6 million shares)...................	--	29.6	1,206.1	--	--	--	--	1,235.7
Cash dividends -- ($.68 per share)...........................	--	--	--	(341.0)	--	--	--	(341.0)
Stockholders' notes issued..........	--	--	--	--	--	(8.8)	--	(8.8)
Stockholders' notes repaid..........	--	--	--	--	--	6.3	--	6.3
Stock award transactions (including 3.6 million common shares)........	--	3.4	72.6	--	--	.7	2.8	79.5

Tax benefit of stock-based awards...	--	--	26.0	--	--	--	--	26.0
Distribution of Williams Communications Groups' common stock............................	--	--	--	(2,047.4)	21.3	18.0	--	(2,008.1)
Other...............................	--	--	11.1	--	--	--	--	11.1
BALANCE, DECEMBER 31, 2001..........	$ --	$518.9	$5,085.1	$ 199.6	$345.1	$(65.0)	$(39.7)	$ 6,044.0

See accompanying notes.

THE WILLIAMS COMPANIES, INC.

CONSOLIDATED STATEMENT OF CASH FLOWS

(MILLIONS)	YEARS ENDED DECEMBER 31, 2001	2000	1999
OPERATING ACTIVITIES:			
Income from continuing operations	$ 835.4	$ 965.4	$ 354.9
Adjustments to reconcile to cash provided from operations:			
Depreciation, depletion and amortization	797.7	646.8	605.5
Provision for deferred income taxes	346.2	440.5	486.0
Impairment of soda ash mining facility	170.0	--	--
Provision for loss on property and other assets	163.7	57.3	21.5
Net gain on dispositions of assets	(92.4)	(14.7)	(34.1)
Provision for uncollectible accounts	203.2	4.7	(.1)
Preferred returns and minority interest in income of consolidated subsidiaries	67.5	58.0	38.2
Tax benefit of stock-based awards	26.0	25.6	76.1
Cash provided (used) by changes in assets and liabilities:			
Accounts and notes receivable	191.4	(1,558.2)	(632.8)
Inventories	43.1	(293.7)	(102.9)
Margin deposits	517.1	(671.7)	(56.5)
Other current assets	121.4	(28.7)	(62.1)
Accounts payable	(289.3)	1,279.1	898.3
Accrued liabilities	287.2	259.7	(158.7)
Changes in current energy risk management and trading assets and liabilities	(742.9)	(218.8)	.8
Changes in noncurrent energy risk management and trading assets and liabilities	(806.1)	(485.2)	(59.1)
Changes in noncurrent deferred income	(4.1)	28.2	91.1
Other, including changes in non-current assets and liabilities	(52.4)	99.5	67.4
Net cash provided by operating activities	1,782.7	593.8	1,533.5
FINANCING ACTIVITIES:			
Proceeds from notes payable	1,830.0	2,190.4	939.6
Payments of notes payable	(2,631.4)	(723.9)	(729.8)
Proceeds from long-term debt	4,035.1	984.6	1,696.4
Payments of long-term debt	(2,139.0)	(749.5)	(1,014.0)
Proceeds from issuance of common stock	1,410.9	75.2	65.2
Dividends paid	(341.0)	(265.8)	(263.7)
Proceeds from sale of limited partner units of consolidated partnership	92.5	--	--
Net proceeds from issuance of preferred interests of consolidated subsidiaries	95.3	546.8	--
Proceeds (payments) from issuance (redemption) of Williams obligated mandatorily redeemable preferred securities of Trust holding only Williams indentures	(194.0)	--	175.0
Payments/dividends to preferred and minority interests	(59.5)	(42.0)	(27.4)
Payments for debt issuance costs	(51.5)	(4.0)	(12.1)
Other -- net	(.1)	.2	50.8
Net cash provided by financing activities	2,047.3	2,012.0	880.0
INVESTING ACTIVITIES:			
Property, plant and equipment:			
Capital expenditures	(1,922.2)	(1,513.2)	(1,794.9)
Proceeds from dispositions	37.3	38.5	27.4
Acquisitions of businesses (primarily property, plant and equipment), net of cash acquired	(1,343.1)	(726.4)	(162.9)
Purchases of investments/advances to affiliates	(574.0)	(183.2)	(347.2)
Proceeds from dispositions of investments and other assets	407.6	47.2	307.4
Proceeds received on advances to affiliates	95.0	--	--
Purchase of assets subsequently leased to seller	(276.0)	--	--
Other -- net	32.1	(.2)	11.1
Net cash used by investing activities	(3,543.3)	(2,337.3)	(1,959.1)
DISCONTINUED OPERATIONS:			
Net cash provided (used) by operating activities	7.6	(45.7)	(49.5)
Net cash provided by financing activities	1,343.4	1,774.7	3,496.9
Net cash used by investing activities	(1,450.8)	(1,868.4)	(3,316.9)
Cash of discontinued operations at spinoff	(96.5)	--	--
Net cash provided (used) by discontinued operations	(196.3)	(139.4)	130.5
Increase in cash and cash equivalents	90.4	129.1	584.9
Cash and cash equivalents at beginning of year	1,210.7	1,081.6	496.7
Cash and cash equivalents at end of year*	$ 1,301.1	$ 1,210.7	$ 1,081.6

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* Includes cash and cash equivalents of discontinued operations of $213.9 million and $483.9 million for 2000 and 1999, respectively.

See accompanying notes.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

DESCRIPTION OF BUSINESS

Operations of The Williams Companies, Inc. (Williams) are located principally in the United States and are organized into three industry groups: Energy Marketing & Trading, Gas Pipeline and Energy Services.

Energy Marketing & Trading is a fully integrated energy marketer which offers price-risk management services and buys, sells and arranges for transportation/transmission of energy commodities -- including natural gas and gas liquids, crude oil and refined products, and electricity -- to local distribution companies, utilities, municipalities, rural electric cooperatives and large industrial customers in North America. Additionally, Energy Marketing & Trading commenced operations in Europe in 2001.

Gas Pipeline is comprised primarily of five interstate natural gas pipelines located throughout the majority of the United States as well as investments in North American natural gas pipeline-related companies. The five Gas Pipeline operating segments have been aggregated for reporting purposes and include Williams Gas Pipelines Central, Kern River Gas Transmission, Northwest Pipeline, Texas Gas Transmission and Transcontinental Gas Pipe Line.

Energy Services includes five operating segments: Exploration & Production, International, Midstream Gas & Liquids, Petroleum Services and Williams Energy Partners. Exploration & Production includes natural gas exploration, production and marketing activities primarily in the Rocky Mountain, Midwest and Gulf Coast regions. During 2001, Exploration & Production acquired Barrett Resources Corporation (Barrett) which was an independent natural gas and oil exploration and production company with producing properties located principally in the Rocky Mountain and Mid-Continent regions of the United States. International includes direct investments in projects in Argentina, Brazil, Venezuela and Lithuania, investments in energy and infrastructure development funds in Asia and South America and soda ash mining operations in Colorado. Midstream Gas & Liquids is comprised of natural gas gathering and processing and treating facilities in the Rocky Mountain, Midwest and Gulf Coast regions of the United States, natural gas liquids pipelines in the Rocky Mountain, Southwest, Midwest and Gulf Coast regions of the United States and assets in Canada including several natural gas liquids extraction and fractionation plants, natural gas liquids pipeline, storage facilities, and a natural gas processing plant. Petroleum Services includes petroleum refining and marketing in Alaska and the Southeast, a petroleum products pipeline and ethanol production and marketing operations in the Midwest region, and retail travel centers concentrated in the Midsouth and along the United States interstate highway system and convenience stores in Alaska. Williams Energy Partners includes a network of storage, transportation and distribution assets for crude petroleum products and ammonia.

BASIS OF PRESENTATION

Effective February 2001, management of certain operations, previously conducted by Energy Marketing & Trading, was transferred to Petroleum Services. These operations included the procurement of crude oil and marketing of refined products produced from the Memphis refinery, for which prior year segment information reflects the transfer. Additionally, the refined product sales activities surrounding certain terminals located throughout the United States were transferred. This sales activity was previously included in the trading portfolio of Energy Marketing & Trading and was therefore reported net of related cost of sales. Following the transfer, these sales are reported on a "gross" basis.

During first-quarter 2001, Williams Energy Partners L.P. completed an initial public offering of approximately 4.6 million common units at $21.50 per unit for net proceeds of approximately $92 million. The initial public offering represents 40 percent of the units, and Williams retains a 60 percent interest in the partnership, including its general partner interest. Williams Energy Partners L.P. and Williams' general partnership interest is reported as Williams Energy Partners, a separate segment within Energy Services, and consists primarily of certain terminals and an ammonia pipeline previously reported within Petroleum Services and Midstream Gas & Liquids, respectively. Also during first-quarter 2001, management of international activities, previously reported in Other, was transferred and the international activities are reported as a separate segment within Energy Services.

On April 23, 2001, Williams distributed 398.5 million shares, or approximately 95 percent, of Williams' communications business, Williams Communications Group, Inc. (WCG), to Williams' shareholders. WCG has been accounted for as discontinued operations, and, accordingly, the accompanying consolidated financial statements and notes reflect the results of operations, net assets and cash flows of WCG as discontinued operations. For information relating to litigation involving the distribution of WCG shares, see Note 19. Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to the continuing operations of Williams (see Note 3).

Certain prior year amounts have been reclassified to conform to current year classifications.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Williams and its majority-owned subsidiaries and investments. Companies in which Williams and its subsidiaries own 20 percent to 50 percent of the voting common stock, or otherwise exercise significant influence over operating and financial policies of the company, are accounted for under the equity method.

USE OF ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Estimates and assumptions which, in the opinion of management, are significant to the underlying amounts included in the financial statements and for which it would be reasonably possible that future events or information could change those estimates include: 1) contingent obligations including guarantees related to WCG obligations; 2) litigation-related contingencies; 3) valuations of energy contracts, including energy-related contracts; 4) environmental remediation obligations; 5) impairment assessments of goodwill and long-lived assets; 6) realization of deferred income tax assets; and 7) Gas Pipeline revenues subject to refund. These estimates are discussed further throughout the accompanying notes.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents include demand and time deposits, certificates of deposit and other marketable securities with maturities of three months or less when acquired.

INVENTORY VALUATION

Inventories are stated at cost, which is not in excess of market, except for certain assets held for energy risk management activities by Energy Marketing & Trading, which are primarily stated at fair value. The cost of inventories is determined using the following methods: certain crude oil and refined products inventories held by Petroleum Services are determined using the first-in, first-out (FIFO) cost method as adjusted for the effects of fair value hedges as prescribed by Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities;" certain natural gas inventories held by Transcontinental Gas Pipe Line are determined using the last-in, first-out (LIFO) cost method; and the cost of the remaining inventories is primarily determined using the average-cost method or market, if lower.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is recorded at cost. Depreciation is provided primarily on the straight-line method over estimated useful lives. Gains or losses from the ordinary sale or retirement of property, plant and equipment for regulated pipelines are credited or charged to accumulated depreciation; other gains or losses are recorded in net income.

Oil and gas exploration and production activities are accounted for under the successful efforts method of accounting. Costs incurred in connection with the drilling and equipping of exploratory wells are capitalized as incurred. If proved reserves are not found, such costs are charged to expense. Other exploration costs, including lease rentals, are expensed as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred. Unproved properties are evaluated annually, or as conditions warrant, to determine any impairment in carrying value. Depreciation, depletion and amortization are provided under the units of production method.

Proved properties, including developed and undeveloped, and costs associated with probable reserves, are assessed for impairment using estimated future cash flows. Estimating future cash flows involves the use of complex judgments such as estimation of the proved and probable oil and gas reserve quantities, risk associated with the different categories of oil and gas reserves, timing of development and production, expected future commodity prices, capital expenditures and production costs.

GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill represents the excess of cost over fair value of assets of businesses acquired. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," approximately $1 billion of goodwill acquired subsequent to June 30, 2001, in the acquisition of Barrett (see Note 2) is not being amortized. All other goodwill is amortized on a straight-line basis over periods from 20 to 40 years. Other intangible assets are amortized on a straight-line basis over periods from three to 25 years. Accumulated amortization at December 31, 2001 and 2000 was $16.3 million and $45.2 million, respectively. Amortization expense was $7 million, $10.7 million and $20.4 million in 2001, 2000 and 1999, respectively. See RECENT ACCOUNTING STANDARDS for further discussion of SFAS No. 142.

TREASURY STOCK

Treasury stock purchases are accounted for under the cost method whereby the entire cost of the acquired stock is recorded as treasury stock. Gains and losses on the subsequent reissuance of shares are credited or charged to capital in excess of par value using the average-cost method.

ENERGY COMMODITY RISK MANAGEMENT AND TRADING ACTIVITIES

Energy Marketing & Trading has energy commodity risk management and trading operations that enter into energy contracts to provide price-risk management services to its third-party customers. Energy contracts utilized in energy commodity risk management and trading activities are valued at fair value in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and Emerging Issues Task Force Issue (EITF) No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." Williams adopted SFAS No. 133 effective January 1, 2001. Such adoption had no impact on the accounting for energy commodity risk management and trading activities. Prior to adopting SFAS No. 133, Energy Marketing & Trading followed the guidance in EITF No. 98-10. Energy contracts include forward contracts, futures contracts, option contracts, swap agreements, commodity inventories, short-and long-term purchase and sale commitments, which involve physical delivery of an energy commodity and energy-related contracts, such as transportation, storage, full requirements, load serving and power tolling contracts. In addition, Williams enters into interest rate swap agreements and credit default swaps to manage the interest rate and credit risk in its energy trading portfolio. These energy contracts and interest rate and credit default swap agreements, with the exception of certain commodity inventories, are recorded in current and noncurrent energy risk management and trading assets and energy risk management and trading liabilities in the Consolidated Balance Sheet. The classification of current versus noncurrent is based on the timing of expected future cash flows. In accordance with SFAS No. 133 and EITF No. 98-10, the net change in fair value of these contracts representing unrealized gains and losses is recognized in income currently and recorded as revenues in the Consolidated Statement of Operations. Energy Marketing & Trading reports its trading operations' physical sales transactions net of the related purchase costs, consistent with fair value accounting for such trading activities. The accounting for Energy Marketing & Trading's energy-related contracts requires Williams to assess whether certain of these contracts are executory service arrangements or leases pursuant to SFAS No. 13, "Accounting for Leases." There currently is not extensive authoritative guidance for determining when an arrangement is a lease or an executory service arrangement. As a result, Williams assesses each of its energy-related contracts and makes the determination based on the substance of each contract focusing on factors such as physical and operational control of the related asset, risks and rewards of owning, operating and maintaining the related asset and other contractual terms.

Fair value of energy contracts is determined based on the nature of the transaction and the market in which transactions are executed. Certain transactions are executed in exchange-traded or over-the-counter markets for which quoted prices in active periods exist. Transactions are also executed in exchange-traded or over-the-counter markets for which quoted market prices may exist; however, the markets may be relatively inactive and price transparency is limited. Certain transactions are executed for which quoted market prices are not available. Quoted market prices for varying periods in active markets are readily available for valuing forward contracts, futures contracts, swap agreements and purchase and sales transactions in the commodity markets in which Energy Marketing & Trading transacts. For contracts or transactions that extend into periods for which actively quoted prices are not available, Energy Marketing & Trading estimates energy commodity prices in the illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices reflected in current transactions and market fundamental analysis. For contracts where quoted market prices are not available, primarily transportation, storage, full requirements, load serving and power tolling contracts, Energy Marketing & Trading estimates fair value using models and other valuation techniques that reflect the best information available under the circumstances. Fair value for energy-related contracts is estimated using valuation techniques that incorporate option pricing theory, statistical and simulation analysis, present value concepts incorporating risk from uncertainty of the timing and amount of estimated cash flows and specific contractual terms. These valuation techniques utilize factors such as quoted energy commodity market prices, estimates of energy commodity market prices in the absence of quoted market prices, volatility factors underlying the positions, estimated correlation of energy commodity prices, contractual volumes, estimated volumes under option and other arrangements, liquidity of the market in which the contract is transacted, and a risk-free market discount rate. Fair value also reflects a risk premium that market participants would consider in their determination of fair value. Regardless of the method for which fair value is determined, the recognized fair value of all contracts also considers the risk of non-performance and credit considerations of the counterparty.

In some cases, Energy Marketing & Trading enters into price-risk management contracts that have forward start dates commencing upon completion of construction and development of assets to be owned and operated by third parties. Until construction commences, revenue recognition and the fair value of these contracts is limited to the amount of any guaranty or similar form of acceptable credit support that encourages the counterparty to perform under the terms of the contract with appropriate consideration for any contractual provisions that provide for contract termination by the counterparty.

The fair value of Energy Marketing & Trading's trading portfolio is continually subject to change due to changing market conditions and changing trading portfolio positions. Determining fair value for these contracts also involves complex assumptions including estimating natural gas and power market prices in illiquid periods and markets, estimating volatility and correlation of natural gas and power prices, evaluating risk arising from uncertainty inherent in estimating cash flows and estimates regarding counterparty performance and credit considerations.

GAS PIPELINE REVENUES

Revenues for sales of products are recognized in the period of delivery, and revenues from the transportation of gas are recognized in the period the service is provided. Gas Pipeline is subject to Federal Energy Regulatory Commission (FERC) regulations and, accordingly, certain revenues collected may be subject to possible refunds upon final orders in pending rate cases. Gas Pipeline records estimates of rate refund liabilities considering Gas Pipeline and other third-party regulatory proceedings, advice of counsel and estimated total exposure, as discounted and risk weighted, as well as collection and other risks.

ENERGY SERVICES REVENUES

Revenues generally are recorded when services have been performed or products have been delivered. A portion of Petroleum Services is subject to FERC regulations and, accordingly, the method of recording these revenues is consistent with Gas Pipeline's method discussed above.

Additionally, revenues from the production of natural gas in properties for which Exploration & Production has an interest with other producers, are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on Exploration & Production's net working interest, which are determined to be non-recoverable through remaining production, are recognized as accounts receivable or accounts payable, as appropriate. Cumulative differences between volumes sold and entitlement volumes are not significant.

DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

On January 1, 2001, Williams adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." This standard, as amended, did not impact the accounting for derivatives within Energy Marketing & Trading's energy commodity risk management and trading activities which are accounted for at fair value as discussed above. All other derivatives are reflected on the balance sheet at their fair value and are recorded in other current assets, other assets and deferred charges, accrued liabilities and other liabilities and deferred income in the Consolidated Balance Sheet as of December 31, 2001.

Derivative instruments held by Williams, other than those utilized in the energy risk management and trading activities, consist primarily of futures contracts, swap agreements, forward contracts and option contracts. Most of these transactions are executed in exchange-traded or over-the-counter markets for which quoted prices in active periods exist. For contracts with lives exceeding the time period for which quoted prices are available, fair value determination involves estimating commodity prices during the illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices reflected in current transactions and market fundamental analysis.

The accounting for changes in the fair value of a derivative depends upon whether it has been designated in a hedging relationship and, further, on the type of hedging relationship. To qualify for designation in a hedging relationship, specific criteria must be met and the appropriate documentation maintained. Hedging relationships are established pursuant to Williams' risk management policies and are initially and regularly evaluated to determine whether they are expected to be, and have been, highly effective hedges. If a derivative ceases to be a highly effective hedge, hedge accounting is discontinued prospectively, and future changes in the fair value of the derivative are recognized in earnings each period. Changes in the fair value of derivatives not designated in a hedging relationship are recognized in earnings each period.

For derivatives designated as a hedge of a recognized asset or liability or an unrecognized firm commitment (fair value hedges), the changes in the fair value of the derivative as well as changes in the fair value of the hedged item attributable to the hedged risk are recognized each period in earnings. If a firm commitment designated as the hedged item in a fair value hedge is terminated or otherwise no longer qualifies as the hedged item, any asset or liability previously recorded as part of the hedged item is recognized currently in earnings.

For derivatives designated as a hedge of a forecasted transaction or of the variability of cash flows related to a recognized asset or liability (cash flow hedges), the effective portion of the change in fair value of the derivative is reported in other comprehensive income and reclassified into earnings in the period in which the hedged item affects earnings. Amounts excluded from the effectiveness calculation and any ineffective portion of the change in fair value of the derivative are recognized currently in earnings. Gains or losses deferred in accumulated other comprehensive income associated with terminated derivatives and derivatives that cease to be highly effective hedges remain in accumulated other comprehensive income until the hedged item affects earnings. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transaction is no longer probable of occurring, any gain or loss deferred in accumulated other comprehensive income is recognized in earnings currently.

On January 1, 2001, Williams recorded a cumulative effect of an accounting change associated with the adoption of SFAS No. 133, as amended, to record all derivatives at fair value. The cumulative effect of the accounting change was not material to net income (loss), but resulted in a $95 million reduction of other comprehensive income (net of income tax benefits of $59 million) related to derivatives which hedge the variable cash flows of certain forecasted energy commodity transactions. Of the transition adjustment recorded in other comprehensive income at January 1, 2001, net losses of approximately $90 million (net of income tax benefits of $56 million) were reclassified into earnings during 2001, offsetting net gains realized in earnings from favorable market movements associated with the underlying transactions being hedged.

With the adoption of SFAS No. 133 on January 1, 2001, the accounting for certain aspects of derivative instruments and hedging activities was different in periods prior to the adoption of SFAS No. 133. Prior to 2001, Williams entered into energy derivative financial instruments and derivative commodity instruments (primarily futures contracts, option contracts and swap agreements) to hedge against market price fluctuations of certain commodity inventories and sales and purchase commitments. Certain of these instruments were not required to be recorded on the balance sheet; there was not a distinction between cash flow and fair value hedges and no ineffectiveness was required to be recorded currently in earnings. Unrealized and realized gains and losses on those hedge contracts were deferred and recognized in income in the same manner as the hedged item. No unrealized gains or losses were required to be reported in other comprehensive income. These contracts were initially and regularly evaluated to determine that there was high correlation between changes in the fair value of the hedge contract and fair value of the hedged item. In instances where the anticipated correlation of price movements did not occur, hedge accounting was terminated and future changes in the value of the instruments were recognized as gains or losses. If the hedged item of the underlying transaction was sold or settled, the instrument was recognized into income (loss).

Williams entered into interest-rate swap agreements to modify the interest characteristics of its long-term debt. These agreements were designated with all or a portion of the principal balance and term of specific debt obligations. These agreements involved the exchange of amounts based on a fixed interest rate for amounts based on variable interest rates without an exchange of the notional amount upon which the payments are based. The difference to be paid or received was accrued and recognized as an adjustment of interest accrued. Gains and losses from terminations of interest-rate swap agreements were deferred and amortized as an adjustment of the interest expense on the outstanding debt over the remaining original term of the terminated swap agreement. In the event the designated debt was extinguished, gains and losses from terminations of interest-rate swap agreements were recognized into income (loss).

MAJOR MAINTENANCE COSTS

Williams incurs planned major maintenance costs at its two refineries and an ethylene production facility and accrues for these costs in advance of the period in which costs are actually incurred. For the refineries, such repairs are completed over a planned cycle of five to six years, with modular components completed each year. For the ethylene facility, major maintenance repairs are scheduled to occur approximately every four years. At December 31, 2001, the total expected cost of the major maintenance projects was approximately $40 million for the refineries and approximately $6 million for the ethylene production facility. The balance of costs to be accrued is approximately $28 million for the refineries and $5 million for the ethylene production facility over the 2002-2005 period.

Accruals are initiated upon completion of the most recent major maintenance project. These projects are completed over periods of several days to several weeks, with annual accruals in advance of costs actually being incurred expected to total approximately $7 million for the refineries and approximately $2 million for the ethylene production facility over the 2002-2005 period.

IMPAIRMENT OF LONG-LIVED ASSETS

Williams evaluates the long-lived assets, including other intangibles and related goodwill, of identifiable business activities for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may not be recoverable. When such a determination has been made, management's estimate of undiscounted future cash flows attributable to the assets is compared to the carrying value of the assets to determine whether an impairment has occurred. If an impairment of the carrying value has occurred, the amount of the impairment recognized in the financial statements is determined by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

For assets identified to be disposed of in the future, the carrying value of these assets is compared to the estimated fair value less the cost to sell to determine if recognition of an impairment is required. Until the assets are disposed of, the estimated fair value is redetermined when related events or circumstances change.

Judgments and assumptions are inherent in management's estimate of undiscounted future cash flows used to determine recoverability of an asset and the estimate of an asset's fair value used to calculate the amount of impairment to recognize. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

CAPITALIZATION OF INTEREST

Williams capitalizes interest on major projects during construction. Interest is capitalized on borrowed funds and, where regulation by the FERC exists, on internally generated funds. The rates used by regulated companies are calculated in accordance with FERC rules. Rates used by unregulated companies are based on the average interest rate on debt. Interest capitalized on internally generated funds, as permitted by FERC rules, is included in non-operating other income (expense) -- net.

EMPLOYEE STOCK-BASED AWARDS

Employee stock-based awards are accounted for under Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock options equals the market price of the underlying stock on the date of grant.

INCOME TAXES

Williams includes the operations of its subsidiaries in its consolidated tax return. Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial basis and the tax basis of Williams' assets and liabilities. Management's judgment and income tax assumptions are used to determine the levels, if any, of valuation allowances associated with deferred tax assets.

EARNINGS PER SHARE

Basic earnings per share are based on the sum of the average number of common shares outstanding and issuable restricted and deferred shares. Diluted earnings per share include any dilutive effect of stock options and, for applicable periods presented, convertible preferred stock.

FOREIGN CURRENCY TRANSLATION

The functional currency of Williams is the U.S. dollar. The functional currency of certain of Williams' continuing foreign operations is the local currency for the applicable foreign subsidiary or equity method investee. These foreign currencies include the Canadian dollar, British pound, Euro, and Brazilian real. Assets and liabilities of certain foreign subsidiaries and equity investees are translated at the spot rate in effect at the applicable reporting date, and the combined statements of operations and Williams' share of the results of operations of its equity affiliates are translated at the average exchange rates in effect during the applicable period. The resulting cumulative translation adjustment is recorded as a separate component of other comprehensive income (loss).

Transactions denominated in currencies other than the functional currency are recorded based on exchange rates at the time such transactions arise. Subsequent changes in exchange rates result in transactions gains and losses which are reflected in the Consolidated Statement of Operations.

ISSUANCE OF EQUITY OF CONSOLIDATED SUBSIDIARY

Sales of equity, common stock or limited partnership units, by a consolidated subsidiary are accounted for as capital transactions with the adjustment to capital in excess of par value. No gain or loss is recognized on these transactions.

SECURITIZATIONS AND TRANSFERS OF FINANCIAL INSTRUMENTS

Williams has agreements to sell, on an ongoing basis, certain of its trade accounts receivable through revolving securitization structures and retains servicing responsibilities as well as a subordinate interest in the transferred receivables. Williams accounts for the securitization of trade accounts receivable in accordance with SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." As a result, the related receivables are removed from the Consolidated Balance Sheet and a retained interest is recorded for the amount of receivables sold in excess of cash received.

Williams determines the fair value of its retained interests based on the present value of future expected cash flows using management's best estimates of various factors, including credit loss experience and discount rates commensurate with the risks involved. These assumptions are updated periodically based on actual results, thus the estimated credit loss and discount rates utilized are materially consistent with historical performance. The fair value of the servicing responsibility is estimated based on internal costs, which approximate market. Costs associated with the sale of receivables are included in nonoperating other income (expense) -- net in the Consolidated Statement of Operations.

RECENT ACCOUNTING STANDARDS

The Financial Accounting Standards Board (FASB) issued SFAS No. 141, "Business Combinations" and SFAS No. 142, "Goodwill and Other Intangible Assets." SFAS No. 141 establishes accounting and reporting standards for business combinations and requires all business combinations to be accounted for by the purchase method. The Statement is effective for all business combinations initiated after June 30, 2001, and any business combinations accounted for using the purchase method for which the date of acquisition is July 1, 2001, or later. SFAS No. 142 addresses accounting and reporting standards for goodwill and other intangible assets. Under the provisions of this Statement, goodwill and intangible assets with indefinite useful lives are no longer amortized, but will be tested annually for impairment. Williams applied the new rules on accounting for goodwill and other intangible assets beginning January 1, 2002. Application of the nonamortization provisions of the Statement will not materially impact the comparability of the Consolidated Statement of Operations. During first-quarter 2002, Williams began the initial impairment tests of goodwill as of January 1, 2002. Preliminary results of these tests have indicated that there will not be a significant unfavorable impact of adopting this standard; however, all tests have not been completed. Approximately $1 billion of goodwill recorded as a result of the Barrett acquisition completed on August 2, 2001, (see Note 2) is not being amortized.

The FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This Statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs and amends FASB Statement No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." The Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Statement is effective for financial statements issued for fiscal years beginning after June 15, 2002. The effect of this standard on Williams' results of operations and financial position is being evaluated. While it is likely there will ultimately be material obligations related to the future retirement of assets such as refineries and pipelines, Williams cannot currently estimate the financial impact at the date of adoption as Williams has not yet completed its evaluation. However, it is Williams' belief that any such impact would be a charge to earnings.

The FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." This Statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," and amends Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations -- Reporting the Effects of Disposal of a Segment of a Business and Extraordinary, Unusual and Infrequently Occurring Events and Transactions." The Statement retains the basic framework of SFAS No. 121, resolves certain implementation issues of SFAS No. 121, extends applicability to discontinued operations, and broadens the presentation of discontinued operations to include a component of an entity. The Statement is being applied prospectively, beginning January 1, 2002. Initial adoption of the Statement did not have any impact on Williams' results of operations or financial position.

NOTE 2. BARRETT ACQUISITION

Through two transactions, Williams acquired all of the outstanding stock of Barrett. On June 11, 2001, Williams acquired 50 percent of Barrett's outstanding common stock in a cash tender offer of $73 per share for a total of approximately $1.2 billion. Williams acquired the remaining 50 percent of Barrett's outstanding common stock on August 2, 2001, through a merger by exchanging each remaining share of Barrett common stock for 1.767 shares of Williams common stock for a total of approximately 30 million shares of Williams common stock valued at $1.2 billion. The value of the 30 million shares of Williams common stock was based on the average market price of Williams common stock for the 2 days before and after the May 7, 2001, announcement of the terms of the acquisition. This acquisition has been accounted for as a purchase business combination with a purchase price, including transaction fees and other related costs, of approximately $2.5 billion, excluding $312 million of debt obligations of Barrett assumed in the acquisition.

Williams' 50 percent share of Barrett's results of operations for the period June 11, 2001 to August 1, 2001, as well as amortization of the excess of Williams' investment over the underlying equity in Barrett's net assets for that period, is included in equity earnings within investing income (loss) in the Consolidated Statement of Operations and Exploration & Production's segment profit. Beginning August 2, 2001, 100 percent of Barrett's results of operations is included in Exploration & Production's revenues and operating income in the Consolidated Statement of Operations, and the majority of these assets are included in Exploration & Production's segment assets.

As of August 2, 2001, Barrett's estimated proved gas and oil reserves were 1.9 trillion cubic feet of gas equivalents. Barrett's assets included long-lived reserves that Williams believes offer opportunity for long-term and steady growth and align strategically with Williams' other assets. Williams is a major gatherer and processor in the Rockies and has natural gas pipelines and gas liquids pipelines that transport product out of the Rockies. In addition, these new gas reserves help to balance the risk profile of Williams' growing power trading portfolio by providing an additional physical and natural hedge against a short natural gas position. As a result of the value that the Barrett acquisition provides to Williams overall, $1.0 billion of goodwill was allocated to Exploration & Production and $105.5 million was allocated to Energy Marketing & Trading.

The following unaudited pro forma information combines the results of operations of Williams and Barrett and incorporates the impact of the Williams shares issued as if the purchase of 100 percent of Barrett occurred at the beginning of each year presented:

	2001	2000
	(MILLIONS, EXCEPT PER-SHARE AMOUNTS)	
Revenues	$11,409.3	$9,879.5
Income from continuing operations	917.1	922.0
Net income (loss)	(396.0)	480.9
Basic earnings (loss) per common share:		
Income from continuing operations	$ 1.78	$ 1.95
Net income (loss)	$ (.77)	$ 1.01
Diluted earnings (loss) per common share:		
Income from continuing operations	$ 1.77	$ 1.93
Net income (loss)	$ (.76)	$ 1.00

Pro forma financial information is not necessarily indicative of results of operations that would have occurred if the acquisition had occurred at the beginning of each year presented or of future results of operations of the combined companies.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition. Fair value is determined based on the nature of the asset acquired or liability assumed and utilizes judgments and assumptions of management. Where available, exchange quoted energy commodity market prices and current interest rate levels were used. When the contract life or estimated reserve life exceeds the time period for which quoted prices are available, judgment is used to estimate the energy commodity prices during the illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices reflected in current transactions and market fundamental analysis. Complex judgments also include estimation of the oil and gas reserve quantities, risk associated with the different categories of oil and gas reserves, timing of development and production of oil and gas reserves, oil and gas capital expenditures necessary to develop the reserves, production costs and discount rate.

	AT AUGUST 2, 2001
	(MILLIONS)
Current deferred income taxes	$ 14.4
Other current assets	113.2
Property, plant and equipment	2,520.4
Goodwill and other assets	1,114.5
Total assets	3,762.5
Current liabilities	134.6
Current energy risk management and trading liabilities	37.0
Long-term debt	312.1
Deferred income taxes	634.7
Noncurrent energy risk management and trading liabilities	61.6
Other liabilities	65.5
Total liabilities	1,245.5
Net assets acquired	$2,517.0

NOTE 3. DISCONTINUED OPERATIONS

EVENTS AROUND THE WCG SEPARATION AND OTHER RELATED INFORMATION

On March 30, 2001, Williams' board of directors approved a tax-free spinoff of WCG to Williams' shareholders. Williams distributed 398.5 million shares, or approximately 95 percent of the WCG common stock held by Williams, to holders of record on April 9, 2001, of Williams' common stock. Distribution of .822399 of a share of WCG common stock for each share of Williams common stock occurred on April 23, 2001.

Williams, prior to the spinoff and in an effort to strengthen WCG's capital structure, entered into an agreement under which Williams contributed an outstanding promissory note from WCG of approximately $975 million and certain other assets, including a building under construction and a commitment to complete the construction. In return, Williams received 24.3 million newly issued common shares of WCG.

The WCG common stock distribution was recorded as a dividend and resulted in a decrease to consolidated stockholders' equity of approximately $2.0 billion, which included an increase to accumulated other comprehensive income of approximately $21.3 million. The WCG shares retained by Williams are included in investments in the Consolidated Balance Sheet. In third-quarter 2001, Williams recognized a $70.9 million loss related to the write-down of this investment due to the decline in value which was determined to be other than temporary (see Note 4). At year-end, Williams wrote off its remaining $25 million investment in WCG common stock as discussed further below. Additionally, receivables include amounts due from WCG of approximately $27 million, net of allowance of $85 million, at December 31, 2001. This amount includes a $21 million deferred payment (net of allowance of $85 million) for services provided to WCG due March 15, 2002. In February 2002, the deferred payment from WCG was extended to September 15, 2002.

Williams, prior to the spinoff, provided indirect credit support for $1.4 billion of WCG's Note Trust Notes through a commitment to make available proceeds of a Williams equity issuance or other permitted redemption sources in the event any one of the following were to occur: (1) a WCG default; (2) downgrading of Williams' senior unsecured debt to Ba1 or below by Moody's Investor's Service, BB or below by Standard &

Poor's, or BB+ or below by Fitch Ratings, if Williams' common stock closing price is below $30.22 for ten consecutive trading days while such downgrade is in effect; or (3) to the extent proceeds from WCG's refinancing or remarketing of certain structured notes prior to March 2004 produces proceeds of less than $1.4 billion. On March 5, 2002, Williams received the requisite approvals on its consent solicitation to amend the terms of the WCG Note Trust Notes. The amendment, among other things, eliminates acceleration of the WCG Note Trust Notes due to a WCG bankruptcy or from a Williams credit rating downgrade. The amendment also affirms Williams' obligations for all payments due with respect to the WCG Note Trust Notes, which are due March, 2004, and allows Williams to fund such payments from any available sources. With the exception of the March and September 2002 interest payments, totaling $115 million, WCG remains indirectly obligated to reimburse Williams for any payments Williams is required to make in connection with the Structured Notes.

Williams has provided a guarantee of WCG's obligations under a 1998 transaction in which WCG entered into an operating lease agreement covering a portion of its fiber-optic network. The total cost of the network assets covered by the lease agreement is $750 million. The lease term initially totaled five years and, if renewed, could extend to seven years. WCG has an option to purchase the covered network assets during the lease term at an amount approximating lessor's cost. On March 6, 2002, a representative of WCG notified Williams that WCG intends to issue a notice so as to be able to purchase the assets in the immediate future. As a result of an agreement between Williams and WCG's revolving credit facility lenders, if Williams gains control of the network assets covered by the lease, Williams may be obligated to return the assets to WCG and the liability of WCG to compensate Williams for such property may be subordinated to the interests of WCG's revolving credit facility lenders and may not mature any earlier than one year after the maturity of WCG's revolving credit facility.

Williams has also provided guarantees on certain performance obligations of WCG totaling approximately $57 million.

Williams has received a private letter ruling from the Internal Revenue Service (IRS) stating that the distribution of WCG common stock would be tax-free to Williams and its stockholders. Although private letter rulings are generally binding on the IRS, Williams will not be able to rely on this ruling if any of the factual representations or assumptions that were made to obtain the ruling are, or become, incorrect or untrue in any material respect. However, Williams is not aware of any facts or circumstances that would cause any of the representations or assumptions to be incorrect or untrue in any material respect. The distribution could also become taxable to Williams, but not Williams shareholders, under the Internal Revenue Code (IRC) in the event that Williams' or WCG's subsequent business combinations were deemed to be part of a plan contemplated at the time of distribution and would constitute a total cumulative change of more than 50 percent of the equity interest in either company.

Under the terms of an amended tax-sharing agreement between WCG and Williams, WCG will remain liable to Williams for federal and state income tax audit adjustments relating to the period from October 1, 1999, through the date of the spinoff, but will not be responsible for any interest accruing through 2005 on such tax deficiencies. With regard to the tax-free status of the spinoff, Williams will have the overall risk that the transaction is tax free, but WCG will have liability to Williams if WCG causes the spinoff to be taxable. Additionally, WCG and Williams have each agreed to be separately responsible for any tax resulting from actions taken by its respective company that violate the IRC requirement relating to a more than 50 percent change in equity interest in either company discussed above and to mutually monitor activities of both companies with respect to this requirement.

As part of the separation of Williams and WCG, both companies entered into service agreements to support ongoing operations of WCG relating primarily to certain human resources services, buildings and facilities, administrative and strategic sourcing services and information technology. Many of these service agreements expired at the end of 2001, however, certain of the agreements are longer in term and some agreements have been amended to extend the terms into 2002. As these service agreements expire, the fees and reimbursements that are paid by WCG will also cease.

Williams, with respect to shares of WCG's common stock that Williams retained, has committed to the IRS to dispose of all of the WCG common stock that it retains as soon as market conditions allow, but in any event not longer than five years after the spinoff. As part of a separation agreement, but subject to an additional favorable ruling by the IRS that such a limitation is not inconsistent with any ruling issued to Williams regarding the tax-free treatment of the spinoff, Williams agreed not to dispose of the retained WCG shares for three years from the date of distribution and to notify WCG of an intent to dispose of such shares. However, on February 28, 2002, Williams filed with the IRS a request to withdraw its request for a ruling that the agreement between Williams and WCG that Williams would not transfer any retained WCG stock for a three year period from the spinoff would not be inconsistent with the favorable tax-free treatment ruling issued to Williams. Williams represented in the withdrawal request that it had abandoned its intent to make the lock-up effective, thereby making the ruling request moot.

SIGNIFICANT EVENTS OCCURRING AFTER THE SEPARATION

In third-quarter 2001, Williams purchased the Williams Technology Center and other ancillary assets (Technology Center) and three corporate aircraft from WCG for $276 million, which represents the approximate actual cost of construction of the Williams Technology Center and the acquisition costs of the ancillary assets and aircraft. Williams then entered into long-term lease arrangements under which WCG is the sole lessee of the Technology Center and aircraft (see Note 13). As a result of this transaction, Williams' Consolidated Balance Sheet includes $28.8 million in current accounts and notes receivable and $137.2 million in noncurrent other assets and deferred charges, net of allowance of $103.2 million, relating to amounts due from WCG (see Note 13).

For information relating to litigation involving the distribution of WCG shares see Note 19.

Recent disclosures and announcements by WCG, including WCG's recent announcement that it might seek to reorganize under the U.S. Bankruptcy Code, have resulted in Williams concluding that it is probable that it will not fully realize the $375 million of receivables from WCG at December 31, 2001 nor recover its remaining $25 million investment in WCG common stock. In addition, Williams has determined that it is probable that it will be required to perform under the $2.21 billion of guarantees and payments obligations discussed above. Other events that have affected Williams' assessment include the credit downgrades of WCG, the bankruptcy of a significant competitor announced on January 28, 2002, and public statements by WCG regarding an ongoing comprehensive review of its bank secured credit arrangements. As a result of these factors, Williams, using the best information available at the time and under the circumstances, has developed an estimated range of loss related to its total WCG exposure. Management utilized the assistance of external legal counsel and an external financial and restructuring advisor in making estimates related to its guarantees and payment obligations and ultimate recovery of the contractual amounts receivable from WCG. At this time, management believes that no loss within the range is more probable than another. Accordingly, Williams has recorded the $2.05 billion minimum amount of the range of loss which is reported in the Consolidated Statement of Operations as a $1.84 billion pre-tax charge to discontinued operations and a $213 million pre-tax charge to continuing operations. Williams recognized a related deferred tax benefit in the Consolidated Statement of Operations of $742.5 million ($68.9 million in continuing operations and $673.6 million in discontinued operations). The ultimate amount of tax benefit realized could be different from the deferred tax benefit recorded, as influenced by potential changes in federal income tax laws and the circumstances upon the actual realization of the tax benefits from WCG's balance sheet restructuring program.

The charge to discontinued operations of $1.84 billion includes the $1.77 billion minimum amount of the estimated range of loss from performance on $2.21 billion of guarantees and payment obligations and approximately $16 million in expenses. With the exception of the interest on the Note Trust Notes and the expenses, Williams has assumed for purposes of this estimated loss that it will become an unsecured creditor of WCG for all or part of the amounts paid under the guarantees and payment obligations. However, it is probable that Williams will not be able to recover a significant portion of the receivables. The estimated loss from the performance of the guarantees and payment obligations is based on the overall estimate of recoveries on amounts receivable discussed below. Due to the amendment of the WCG Note Trust Notes discussed above, $1.1 billion of the accrued loss will be classified as a long-term liability in the Consolidated Balance Sheet.

The charge to continuing operations of $213 million includes estimated losses from an assessment of the recoverability of carrying amounts of the $106 million deferred payment for services provided to WCG, the $269 million minimum lease payment receivable from WCG, and a remaining $25 million investment in WCG common stock. The $85 million provision on the deferred payment is based on the overall estimate of recoveries on amounts receivable using the same assumptions on collectability as discussed below. The $103 million provision on the minimum lease payments receivable is based on an estimate of the fair value of the leased assets. The $25 million write-off of the WCG investment is based on management's assessment of realization as a result of WCG's balance sheet restructuring program.

The estimated range of loss assumes that Williams, as a creditor of WCG, will recover only a portion of its unsecured claims against WCG. Such claims include a $2.21 billion receivable from performance on guarantees and payment obligations and a $106 million deferred payment for services provided to WCG. With the assistance of external legal counsel and an external financial and restructuring advisor, and considering the best information available at the time and under the circumstances, management developed a range of loss on these receivables with a minimum loss of 80 percent on claims in a bankruptcy of WCG. Estimating the range of loss as a creditor involves making complex judgments and assumptions about uncertain outcomes. The actual loss may ultimately differ from the recorded loss due to changes in numerous factors, which include, but are not limited to, the future demand for telecommunications services and the state of the telecommunications industry, WCG's individual performance, and the nature of the restructuring of WCG's balance sheet. There could be additional losses recognized in the future, a portion of which may be reflected as discontinued operations.

The minimum amount of loss in the range is estimated based on recoveries from a successful reorganization process under Chapter 11 of the U.S. Bankruptcy Code. Recoveries after a successful reorganization process depend, among other things, on the impact of a bankruptcy on WCG's financial performance and WCG's ability to continue uninterrupted business services to its customers and to maintain relationships with vendors. To estimate recoveries of the unsecured creditors, Williams estimated an enterprise value of WCG using a present value analysis and reduced the enterprise value by the level of secured debt which may exist in WCG's restructured balance sheet. In its estimate of WCG's enterprise value, Williams considered a range of cash flow estimates based on information from WCG and from other external sources. Future cash flow projections are valued using discount rates ranging from 17 percent to 25 percent. The range of cash flows is based on different scenarios related to the growth, if any, of WCG's revenues and the impact that a bankruptcy may have on revenue growth. The range of discount rates considers WCG's assumed restructured capital structure and the market return that equity investors may require to invest in a telecommunications business operating in the current distressed industry environment. The range of loss also considers recoveries based on transaction values from recent telecommunications restructurings and from a liquidation of WCG's assets.

Should WCG go into bankruptcy under Chapter 7 of the U.S. Bankruptcy Code, recoveries under a liquidation would include factors such as the nature of WCG's assets, the value of operating assets in a distressed telecommunications market, the cost of liquidation, operating losses during the period of liquidation, the length of liquidation period and claims of creditors superior to those of Williams' unsecured claims.

SUMMARIZED RESULTS OF DISCONTINUED OPERATIONS

Summarized results of discontinued operations for the years ended December 31, 2001, 2000 and 1999, are as follows:

	2001	2000	1999
		(MILLIONS)	
Revenues	$ 329.5*	$ 818.8	$ 575.6
Loss from operations:			
Loss before income taxes	(271.3)*	(252.4)	(272.0)
Estimated before tax loss on disposal of WCG's Solutions segment	--	(323.9)	--
Estimated losses attributable to probable performance on WCG guarantee obligations	(1,839.2)	--	--
Benefit for income taxes	797.4	156.8	73.3
Cumulative effect of change in accounting principle	--	(21.6)	--
Loss from discontinued operations	$(1,313.1)	$(441.1)	$(198.7)

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* Represents results of operations from January 1, 2001 through April 23, 2001.

On January 25, 2001, WCG's board of directors approved a plan for WCG's management to divest operations that previously comprised the Solutions segment. On January 29, 2001, WCG signed an agreement to sell the domestic and Mexican operations of Solutions to Platinum Equity, LLC. This sale closed in first-quarter 2001. WCG divested its remaining Canadian Solutions operations in 2001. The estimated pre-tax loss on disposal of WCG's Solutions segment in 2000 represents the pre-tax estimated loss on sale, including exit costs and the pre-tax estimated operating losses of Solutions from January 1, 2001, to the anticipated disposal date. The 2001 benefit for income taxes attributable to discontinued operations includes an approximately $40 million benefit resulting from Williams finalizing the tax basis of the businesses disposed.

Prior to January 1, 2000, Williams' revenue recognition policy on WCG Solutions' new system sales and upgrades had been to recognize revenues under the percentage-of-completion method. A portion of the revenues on the contracts was initially recognized upon delivery of equipment with the remaining revenues under the contract being recognized over the installation period based on the relationship of incurred labor to total estimated labor. In light of the new guidance in SAB No. 101, effective January 1, 2000, Williams changed its method of accounting for new systems sales and upgrades from the percentage-of-completion method to the completed-contract method. The cumulative effect of the accounting change resulted in a charge to the 2000 loss on discontinued operations of $21.6 million (net of income tax benefits of $14.9 million and minority interest of $21 million).

In October 1999, WCG completed an initial public offering of approximately 34 million shares of its common stock at $23 per share for proceeds of approximately $738 million. In addition, approximately 34 million shares of common stock were privately sold in concurrent investments by SBC Communications Inc., Intel Corporation, and Telefonos de Mexico S.A. de C.V. for proceeds of $738.5 million. These transactions resulted in a reduction of Williams' ownership interest in WCG from 100 percent to 85.3 percent. In accordance with Williams' policy regarding the issuance of subsidiary's common stock, Williams recognized a $1.17 billion increase to Williams' capital in excess of par, a $3.4 million decrease to accumulated other comprehensive income, and an initial increase of $307 million to Williams' minority interest liability. The issuances of stock by WCG were not subject to federal income taxes.

NET ASSETS OF DISCONTINUED OPERATIONS

Net assets of discontinued operations as of December 31, 2000, are as follows:

	2000 (MILLIONS)
Current assets	$1,206.4
Investments	619.9
Property, plant and equipment	5,228.5
Other assets and goodwill	444.0
Total assets	7,498.8
Current liabilities	968.8
Long-term debt	3,511.9
Other liabilities and deferred income	453.9
Minority and preferred interest in consolidated subsidiaries	285.8
Total liabilities and minority interest	5,220.4
	2,278.4
Consolidated tax impact of discontinued operations	190.5
Consolidated minority interest in WCG	(178.7)
Net assets of discontinued operations	$2,290.2

NOTE 4. INVESTING ACTIVITIES

Investing income (loss) for the years ended December 31, 2001, 2000 and 1999, is as follows:

	2001	2000	1999
		(MILLIONS)	
Equity earnings (losses)*	$ 22.7	$ 21.6	$(6.3)
Write-down of investment in WCG stock	(95.9)	--	--
Income (loss) from investments*	(23.3)	0.8	--
Loss provision for WCG receivables (see Note 3)	(188.0)	--	--
Interest income and other	86.1	83.7	31.4
Total	$(198.4)	$106.1	$25.1

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* Items also included in segment profit.

Williams recognized a $94.2 million charge in third-quarter 2001, representing declines in the value of certain investments, including $70.9 million related to Williams' investment in WCG and the $23.3 million related to loss from other investments, which were determined to be other than temporary. These determinations were primarily based on the continued depressed market values of these investments and the overall market value decline experienced by related industry sectors. In addition, a $25 million charge relating to Williams' remaining investment in WCG common stock was recorded in conjunction with Williams' assessment of realization as a result of WCG's balance sheet restructuring program. The total charges of $119.2 million are included in investing income (loss) and are reflected in net income (loss) with no associated tax benefit.

Investments at December 31, 2001 and 2000, are as follows:

	2001	2000
	(MILLIONS)	
Equity method:		
Gulfstream Pipeline, LLC -- 50%	$ 467.8	$ 17.1
Alliance Pipeline -- 14.6%	186.8	183.6
Longhorn Partners Pipeline, L.P. -- 32.1%	105.1	105.3
Discovery Pipeline -- 50%	70.2	87.6
Accroven -- 49.3%	57.1	--
Alliance Aux Sable -- 14.6%	53.9	57.6
AB Mazeikiu Nafta -- 33%	39.1	61.2
Other	191.2	242.2
	1,171.2	754.6
Cost method:		
Gulf Liquids Holdings, LLC	92.2	44.5
Algar Telecom S.A. -- common and preferred stock	52.8	52.8
Asian Infrastructure Fund	36.3	40.5
Other	95.1	72.5
	276.4	210.3
Ferrellgas Partners L.P. senior common units	--	193.9
Advances to affiliates and other	115.5	209.8
	$1,563.1	$1,368.6

Dividends and distributions received from companies carried on the equity basis were $51 million, $21 million and $14 million in 2001, 2000 and 1999, respectively.

The Ferrellgas Partners L.P. senior common units were sold in 2001 for $199.1 million. Williams recognized no gain or loss associated with this transaction as the purchase price of the units sold approximated their carrying value. As part of the sale, Williams is party to a put agreement whereby the purchaser's lenders can require Williams to repurchase the units upon certain events of default by the purchaser or failure or default by Williams under any of its debt obligations greater than $60 million. The total contingent obligation under the put agreement at December 31, 2001, was $99.6 million. Williams' contingent obligation reduces as purchaser's payments are made to the lender. The put agreement expires December 30, 2005. There have been no events of default and the purchaser has performed as required under payment terms with the lender.

At December 31, 2001, commitments for additional investments in Gulfstream Pipeline, LLC, certain international cost investments and advances to Longhorn Partners Pipeline, L.P. are $233 million.

NOTE 5. ASSET SALES, IMPAIRMENTS AND OTHER ACCRUALS

The $170 million impairment charge, reflected in the Consolidated Statement of Operations, relates to the soda ash mining facility located in Colorado. The facility, which began production in fourth-quarter 2000, experienced higher than expected construction costs and implementation difficulties through December 2001. As a result, an impairment of the assets based on management's estimate of the fair value was recorded in fourth-quarter 2001. Management's estimate was based on the present value of discounted future cash flows. In addition, management engaged an outside business consulting firm to provide further information to be utilized in management's estimation. Future events and the use of different judgments and/or assumptions could result in the recognition of an additional impairment charge.

Significant gains or losses from asset sales, impairments and other accruals included in other (income) expense -- net within segment costs and expenses for the years ended December 31, 2001, 2000 and 1999, are as follows:

	(GAINS) LOSSES		
	2001	2000	1999
	(MILLIONS)		
ENERGY MARKETING & TRADING			
Impairment of plant for terminated expansion	$ 13.3	$ --	$ --
Guarantee loss accruals and impairments	--	47.5	--
Impairment of distributed power services business	--	16.3	--
Gain on sale of certain retail gas and electric operations	--	--	(22.3)
GAS PIPELINE			
Gain on sale of limited partner units of Northern Border Partners, L.P.	(27.5)	--	--
Loss accrual for royalty claims (see Note 19)	18.3	--	--
ENERGY SERVICES:			
EXPLORATION & PRODUCTION			
Gain on sale of certain interests in gas producing properties	--	--	(14.7)
MIDSTREAM GAS & LIQUIDS			
Impairment of south Texas assets	13.8	--	--
PETROLEUM SERVICES			
Impairment and other loss accruals for travel centers	14.7	--	--
Gain on sale of certain convenience stores	(75.3)	--	--
Impairment of end-to-end mobile computing systems business	12.1	11.9	--

The guarantee loss accruals and impairments of $47.5 million in 2000 include impairment charges resulting from the decision to discontinue mezzanine lending services, and the accruals represent the estimated liabilities associated with guarantees of third-party lending activities.

NOTE 6. PROVISION FOR INCOME TAXES

The provision for income taxes from continuing operations includes:

	2001	2000	1999
	(MILLIONS)		
Current:			
Federal	$242.2	$160.4	$(286.7)
State	28.7	24.7	28.1
Foreign	13.1	4.3	3.4
	284.0	189.4	(255.2)
Deferred:			
Federal	295.5	379.4	465.5
State	33.0	63.8	21.1
Foreign	17.7	(2.7)	(.6)
	346.2	440.5	486.0
Total provision	$630.2	$629.9	$ 230.8

Reconciliations from the provision for income taxes from continuing operations at the federal statutory rate to the provision for income taxes are as follows:

	2001	2000	1999
	(MILLIONS)		
Provision at statutory rate	$513.0	$558.4	$205.0
Increases (reductions) in taxes resulting from:			
State income taxes (net of federal benefit)	40.2	57.5	32.0
Foreign operations-net	12.2	2.1	(1.6)
Change in valuation allowance	44.5	--	--
Other -- net	20.3	11.9	(4.6)
Provision for income taxes	$630.2	$629.9	$230.8

Significant components of deferred tax liabilities and assets as of December 31, 2001 and 2000, are as follows:

	2001	2000
	(MILLIONS)	
Deferred tax liabilities:		
Property, plant and equipment	$3,075.1	$2,268.6
Energy risk management and trading -- net	1,023.1	368.3
Investments	510.2	525.3
Other	170.6	211.5
Total deferred tax liabilities	4,779.0	3,373.7
Deferred tax assets:		
Guarantee obligations related to WCG	742.5	--
Minimum tax credits	249.0	241.7
Accrued liabilities	245.4	230.5
Investments	173.3	--
Receivables	63.1	2.5
Loss carryovers	73.5	--
Rate refunds	35.7	19.4
Other	120.5	80.6
Total deferred tax assets	1,703.0	574.7
Valuation allowance	173.3	--
Net deferred tax assets	1,529.7	574.7
Overall net deferred tax liabilities	$3,249.3	$2,799.0

Cash payments for income taxes (net of refunds) were $87 million and $112 million in 2001 and 2000, respectively. In 1999, cash refunds exceeded cash payments resulting in a net refund of $387 million. Federal tax refunds received in 1999 are reflected as current tax benefits with offsetting deferred tax provisions attributable to temporary differences between the book and tax basis of certain assets.

Valuation allowances were established during 2001 for deferred tax assets from basis differences in investments for which the ultimate realization of the tax asset may be dependent on future capital gains. The recording of the investment in the retained shares of WCG after the spinoff (see Note 3) resulted in a $129 million tax asset for which a valuation allowance of $129 million was established. The remaining $44 million of the tax asset, for which a valuation allowance was established, resulted from the financial impairment of certain investments during 2001 (see Note 4).

The merger with Barrett (see Note 2) resulted in $620 million of net liability added to Williams' deferred tax balances as of the merger date. Included in this amount was $70 million of deferred tax assets for pre-affiliation federal net operating loss carryovers which are expected to be utilized by Williams prior to expiration of the carryovers in 2011 through 2018.

NOTE 7. EXTRAORDINARY GAIN

On December 17, 1999, Williams sold its retail propane business, Thermogas L.L.C. (Thermogas), previously a subsidiary of MAPCO, to Ferrellgas Partners L.P. (Ferrellgas) for $443.7 million, including $175 million in senior common units of Ferrellgas. The sale resulted from an unsolicited offer from Ferrellgas and yielded an after-tax gain of $65.2 million (net of a $47.9 million provision for income taxes), which is reported as an extraordinary gain. The results of operations from this business are not significant to consolidated net income for 1999. Thermogas operations for 1999 are reported within the Energy Marketing & Trading segment.

NOTE 8. EARNINGS PER SHARE

Basic and diluted earnings per common share are computed for the years ended December 31, 2001, 2000 and 1999, as follows:

	2001	2000	1999
	(DOLLARS IN MILLIONS, EXCEPT PER-SHARE AMOUNTS; SHARES IN THOUSANDS)		
Income from continuing operations	$ 835.4	$ 965.4	$ 354.9
Convertible preferred stock dividends	--	--	(2.8)
Income from continuing operations available to common stockholders for basic earnings per share	835.4	965.4	352.1
Effect of dilutive securities:			
Convertible preferred stock dividends	--	--	2.8
Income from continuing operations available to common stockholders for diluted earnings per share	$ 835.4	$ 965.4	$ 354.9
Basic weighted-average shares	496,935	444,416	436,117
Effect of dilutive securities:			
Convertible preferred stock	--	--	5,403
Stock options	3,632	4,904	5,395
Diluted weighted-average shares	500,567	449,320	446,915
Earnings per share from continuing operations:			
Basic	$ 1.68	$ 2.17	$ .81
Diluted	$ 1.67	$ 2.15	$ .79

Approximately 15.3 million, 7.2 million and 6.2 million options to purchase shares of common stock with weighted-average exercise prices of $36.12, $43.11 and $38.56, respectively, were outstanding on December 31, 2001, 2000 and 1999, respectively, but have been excluded from the computation of diluted earnings per share. Inclusion of these shares would have been antidilutive, as the exercise prices of the options exceeded the average market prices of the common shares for the respective years.

NOTE 9. EMPLOYEE BENEFIT PLANS

The following table presents the changes in benefit obligations and plan assets for pension benefits and other postretirement benefits for the years indicated. It also presents a reconciliation of the funded status of these benefits to the amount recognized in the Consolidated Balance Sheet at December 31 of each year indicated. The year 2000 disclosure excludes WCG which has been accounted for as discontinued operations (see Note 1). Subsequent measurement of the impact of the spinoff of WCG identified additional benefit obligations and plan assets of $2.3 million and $11.8 million, respectively, which have been included in the table as a divestiture in the year 2001.

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2001	2000	2001	2000
	(MILLIONS)			
Change in benefit obligation:				
Benefit obligations at beginning of year	$ 937.8	$ 791.5	$ 466.8	$ 443.3
Service cost	37.0	34.1	6.9	7.5
Interest cost	71.6	69.6	29.5	33.1
Plan participants' contributions	--	--	2.7	2.0
Amendments	--	4.7	--	--
Divestiture	(2.3)	--	--	--
Special termination benefit cost	--	11.6	--	1.4
Actuarial loss	44.5	111.4	6.9	.5
Benefits paid	(65.3)	(85.1)	(23.8)	(21.0)
Benefit obligation at end of year	1,023.3	937.8	489.0	466.8
Change in plan assets:				
Fair value of plan assets at beginning of year	981.5	1,079.9	254.2	252.5
Actual return on plan assets	(81.4)	(29.1)	(14.4)	(6.5)
Divestiture	(11.8)	--	--	--
Employer contributions	63.0	15.8	28.9	27.2
Plan participants' contributions	--	--	2.7	2.0
Benefits paid	(65.3)	(61.7)	(23.8)	(21.0)
Settlement benefits paid	--	(23.4)	--	--
Fair value of plan assets at end of year	886.0	981.5	247.6	254.2
Funded status	(137.3)	43.7	(241.4)	(212.6)
Unrecognized net actuarial (gain) loss	254.8	22.2	37.9	(8.1)
Unrecognized prior service credit	(11.4)	(13.5)	(1.3)	(1.2)
Unrecognized transition (asset) obligation	.4	(.2)	44.8	48.9
Prepaid (accrued) benefit cost	$ 106.5	$ 52.2	$(160.0)	$(173.0)

Amounts recognized in the Consolidated Balance Sheet consist of:

Prepaid benefit cost	$ 135.1	$ 79.7	$ --	5.9
Accrued benefit cost	(34.1)	(27.5)	(160.0)	(178.9)
Intangible asset	1.9	--	--	--
Accumulated other comprehensive income (before tax)	3.6	--	--	--
Prepaid (accrued) benefit cost	$ 106.5	$ 52.2	$(160.0)	$(173.0)

Net pension and other postretirement benefit expense consists of the following:

	PENSION BENEFITS		
	2001	2000	1999
	(MILLIONS)		
Components of net periodic pension expense:			
Service cost	$37.0	$34.1	$36.0
Interest cost	71.6	69.6	65.1
Expected return on plan assets	(98.8)	(96.3)	(89.6)
Amortization of transition asset	(.6)	(.8)	(.7)
Amortization of prior service credit	(2.1)	(2.1)	(2.4)
Recognized net actuarial loss	.5	--	2.1
Regulatory asset amortization	4.8	4.4	7.2
Settlement/curtailment gain	--	--	(5.6)
Special termination benefit cost	--	11.6	2.2
Net periodic pension expense	$12.4	$20.5	$14.3

	OTHER POSTRETIREMENT BENEFITS		
	2001	2000	1999
	(MILLIONS)		
Components of net periodic postretirement benefit expense:			
Service cost	$ 6.9	$ 7.5	$ 8.5
Interest cost	29.5	33.1	29.9
Expected return on plan assets	(22.6)	(17.3)	(14.3)
Amortization of transition obligation	4.1	4.1	4.0
Amortization of prior service cost	.1	.2	.1
Recognized net actuarial loss (gain)	(2.6)	(.9)	.3
Regulatory asset amortization	14.7	8.7	9.0
Special termination benefit cost	--	1.4	--
Net periodic postretirement benefit expense	$ 30.1	$ 36.8	$ 37.5

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets were $65.7 million, $51.9 million and $19.7 million, respectively, as of December 31, 2001, and $65.0 million, $50.4 million and $22.5 million, respectively, as of December 31, 2000.

The following are the weighted-average assumptions utilized as of December 31 of the year indicated:

	PENSION BENEFITS		OTHER POSTRETIREMENT BENEFITS	
	2001	2000	2001	2000
Discount rate	7.5%	7.5%	7.5%	7.5%
Expected return on plan assets	10	10	10	10
Expected return on plan assets (net of effective tax rate)	N/A	N/A	8.2	6
Rate of compensation increase	5	5	N/A	N/A

The annual assumed rate of increase in the health care cost trend rate for 2002 is 11.8 percent, and systematically decreases to 5 percent by 2015.

The various nonpension postretirement benefit plans which Williams sponsors provide for retiree contributions and contain other cost-sharing features such as deductibles and coinsurance. The accounting for these plans anticipates future cost-sharing changes to the written plans that are consistent with Williams' expressed intent to increase the retiree contribution rate generally in line with health care cost increases.

The health care cost trend rate assumption has a significant effect on the amounts reported. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	POINT INCREASE	POINT DECREASE
	(MILLIONS)	
Effect on total of service and interest cost components....	$ 5.2	$ (4.2)
Effect on postretirement benefit obligation................	66.3	(54.3)

The amount of postretirement benefit costs deferred as a regulatory asset at December 31, 2001 and 2000, is $56 million and $84 million, respectively, and is expected to be recovered through rates over approximately 13 years.

Williams maintains various defined-contribution plans. Williams recognized costs related to continuing operations of $36 million in 2001, $30 million in 2000 and $29 million in 1999 for these plans.

NOTE 10. INVENTORIES

Inventories at December 31, 2001 and 2000, are as follows:

	2001	2000
	(MILLIONS)	
Raw materials:		
Crude oil...	$117.7	$ 70.0
Other...	1.3	1.6
	119.0	71.6
Finished goods:		
Refined products..	265.0	269.6
Natural gas liquids.......................................	142.6	200.2
General merchandise.......................................	14.5	12.5
	422.1	482.3
Materials and supplies......................................	134.6	122.9
Natural gas in underground storage..........................	136.4	169.0
Other...	1.7	2.6
	$813.8	$848.4

As of December 31, 2001 and 2000, approximately 35 percent and 54 percent of inventories, respectively, were stated at fair value. Inventories, primarily related to energy risk management and trading activities, stated at fair value at December 31, 2001 and 2000, included refined products of $90.8 million and $195.1 million, respectively; natural gas in underground storage of $65.3 million and $125.8 million, respectively; and natural gas liquids of $97.9 million and $124.4 million, respectively. Inventories determined using the LIFO cost method were approximately five percent and three percent of inventories at December 31, 2001 and 2000, respectively. Certain crude oil and refined products inventories determined using the FIFO cost method and adjusted for the effects of fair value hedges, as prescribed by SFAS No. 133 were approximately 25 percent of inventories at December 31, 2001. The remaining inventories were primarily determined using the average-cost method.

NOTE 11. PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment at December 31, 2001 and 2000, is as follows:

	2001	2000
	(MILLIONS)	
Cost:		
Energy Marketing & Trading	$ 378.9	$ 299.8
Gas Pipeline	9,929.4	9,084.9
Energy Services:		
Exploration & Production	3,267.1	526.3
International	800.1	820.3
Midstream Gas & Liquids	5,512.4	5,098.9
Petroleum Services	2,722.8	2,588.2
Williams Energy Partners	382.8	341.0
Other	281.9	269.4
	23,275.4	19,028.8
Accumulated depreciation, depletion and amortization	(5,556.2)	(4,822.9)
	$17,719.2	$14,205.9

Depreciation, depletion and amortization expense for property, plant and equipment was $790.7 million, $636.1 million and $585.1 million, respectively, in 2001, 2000 and 1999.

Included in gross property, plant and equipment at December 31, 2001 and 2000, is approximately $1.1 billion and $940 million, respectively, of construction in progress which is not yet subject to depreciation. In addition, property of Exploration & Production includes approximately $839 million at December 31, 2001, of capitalized costs from the Barrett acquisition (see Note 2) related to properties with probable reserves not yet subject to depletion.

Commitments for construction and acquisition of property, plant and equipment are approximately $771 million at December 31, 2001.

Included in net property, plant and equipment is approximately $1.8 billion and $1.9 billion at December 31, 2001 and 2000, respectively, related to amounts in excess of the original cost of the regulated facilities within Gas Pipeline as a result of Williams' and prior acquisitions. This amount is being amortized over the estimated remaining useful lives of these assets at the date of acquisition. Current FERC policy does not permit recovery through rates for amounts in excess of original cost of construction.

NOTE 12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Under Williams' cash-management system, certain subsidiaries' cash accounts reflect credit balances to the extent checks written have not been presented for payment. The amounts of these credit balances included in accounts payable are $32 million at December 31, 2001, and $70 million at December 31, 2000.

Accrued liabilities at December 31, 2001 and 2000, are as follows:

	2001	2000
	(MILLIONS)	
Employee costs	$ 371.2	$ 335.8
Deposits received from customers relating to energy risk management and trading and hedging activities	265.5	244.6
Interest	213.0	151.3
Taxes other than income taxes	165.4	128.5
Income taxes	105.7	18.4
Rate refunds	95.9	72.1
Other	748.5	436.7
	$1,965.2	$1,387.4

NOTE 13. DEBT, LEASES AND BANKING ARRANGEMENTS

NOTES PAYABLE

During 2001, Williams' commercial paper program, backed by a short-term credit facility, was increased from $1.7 billion to $2.2 billion. At December 31, 2001 and 2000, $1.4 billion and $1.7 billion, respectively, of commercial paper was outstanding under the respective programs. Interest rates vary with current market conditions. In January 2002, $300 million of commercial paper was repaid with proceeds from the issuance of long-term debt obligations and, as such, $300 million is classified as long-term as discussed below. In addition, Williams has entered into various other short-term credit agreements, as discussed below, with amounts outstanding totaling $300 million at December 31, 2001, as compared to $350 million at December 31, 2000. The weighted-average interest rate on all short-term borrowings at December 31, 2001 and 2000, was 3.33 percent and 7.18 percent, respectively.

In June 2001, Williams entered into a $200 million (amended in July to $300 million) short-term debt obligation expiring January 2002. The interest rate varies based on LIBOR plus .875 with an interest rate of 2.81 percent at December 31, 2001. In January 2002, this debt obligation was repaid with proceeds from the issuance of long-term debt obligations and, as such, is classified as long-term as discussed below.

In July 2001, Williams issued $300 million in floating rate notes due July 2002. The interest rate varies based on LIBOR plus .875 percent and was 3.15 percent at December 31, 2001.

LONG-TERM DEBT

Long-term debt at December 31, 2001 and 2000, is as follows:

	WEIGHTED AVERAGE INTEREST RATE*	2001	2000
		(MILLIONS)	
Revolving credit loans	3.3%	$ 53.7	$ 350.0
Commercial paper	3.4	300.0	--
Debentures 6.25% -- 10.25%, payable 2003 -- 2031	7.4	1,585.4	1,103.5
Notes, 5.1% -- 9.45%, payable through 2031(1)	7.2	7,345.3	4,856.8
Notes, adjustable rate, payable through 2004	2.9	1,192.9	2,080.4
Other, including capitalized leases of $9.3 million in 2001, payable through 2016	7.8	60.2	73.9
		10,537.5	8,464.6
Current portion of long-term debt		(1,036.8)	(1,634.1)
		$ 9,500.7	$ 6,830.5

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* At December 31, 2001.

(1) $240 million, 6.125% notes, payable 2012, redeemed at par in February 2002, and $400 million of 6.75% notes, payable 2016, putable/callable in 2006.

For financial statement reporting purposes at December 31, 2001, $300 million of commercial paper, $300 million of short-term debt obligations and $244 million of long-term debt obligations due within one year, which would have otherwise been classified as current, have been classified as noncurrent based on Williams' intent and ability to refinance on a long-term basis. In January 2002, in connection with the issuance of the FELINE PACS (see Note 23), Williams issued $1.1 billion of 6.5 percent long-term debt obligations due in 2007, but subject to remarketing in 2004. Proceeds from the issuance of these long-term debt obligations were sufficient to complete these refinancings.

Under the terms of Williams' $700 million revolving credit agreement, Northwest Pipeline, Transcontinental Gas Pipe Line and Texas Gas Transmission have access to various amounts of the facility, while Williams (Parent) has access to all unborrowed amounts. Interest rates vary with current market conditions. At December 31, 2001, no amounts were outstanding under this revolving credit agreement. Additionally, certain Williams subsidiaries have revolving credit facilities with a total capacity of $110 million at December 31, 2001.

Significant long-term debt issuances and retirements, other than amounts under revolving credit agreements, in 2001 are as follows:

ISSUE/TERMS	DUE DATE	PRINCIPAL AMOUNT (MILLIONS)
Issuance of long-term debt in 2001:		
7.875% notes	2021	$750.0
7.125% notes	2011	750.0
7.5% debentures	2031	700.0
6.676% notes (Kern River Gas Transmission)	2002-2016	510.0
7.75% notes	2031	480.0
6.75% Putable Asset Term Securities(1)	2016	400.0
7% notes (Transcontinental Gas Pipe Line)	2011	300.0
Adjustable rate notes (Williams Energy Partners)	2004	90.0
Retirements of long-term debt in 2001:		
Adjustable rate notes	2001	$500.0
6.72% notes (Kern River Gas Transmission)	2001	434.7
6.125% notes	2001	300.0
7.08% debentures (Transcontinental Gas Pipe Line)(2)	2026	192.5
9.375% notes	2001	34.8
6.42% notes (Kern River Gas Transmission)	2001	25.8
Various notes, 6.65%-9.45%	2001	120.4
Various notes, adjustable rate	2001	15.5

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(1) Putable/callable in 2006.

(2) Subject to redemption at par at the option of the debtholder in 2001.

In connection with the Barrett acquisition (see Note 2), Williams' December 31, 2001 Consolidated Balance Sheet includes $155 million of debt obligations of Barrett. Barrett's debt obligations consist of $150 million principal amount of 7.55 percent notes due 2007, which are guaranteed by Williams, and $5 million from purchase price allocation. Additionally, Williams repaid $155 million of debt obligations under Barrett's bank-credit facility in fourth-quarter 2001.

The agreements governing Williams' debt contain covenants and, in some cases, conditions for future borrowings, with which Williams believes it is currently in compliance. The conditions for future borrowings include the absence of default under such agreements, continued accuracy of the representations and warranties contained in such agreements and absence of any material adverse changes. Additionally, the agreements governing Williams' debt include limitations upon liens on Williams' assets with certain exceptions, including purchase money liens, liens existing on property when acquired by Williams, liens on receivables, and liens payable solely out of the proceeds of oil, gas or other minerals produced from the property subject to the lien, as further defined in the agreements and indentures. Most of Williams' private debt agreements, including the $2.2 billion short-term credit facility backing Williams' commercial paper program and $700 million revolving credit agreement, are subject to compliance with certain financial covenants, including a requirement that Williams' net debt, as defined in the governing agreements, not exceed 65 percent of consolidated net worth plus net debt, each as defined in the governing agreements. Consolidated net worth is defined as total assets less liabilities and minority and preferred interests in consolidated subsidiaries plus certain minority interests as defined in the debt agreements. Net debt is defined as all debt, other than non-recourse debt, as well as certain Williams' guarantees as defined in the agreements less cash and cash equivalents. Williams' ratio of net debt to consolidated net worth plus net debt at December 31, 2001 was 61.5 percent. Following the January 2002 issuance of the FELINE PACS (see

Note 23), the definition of consolidated net worth was amended to include those securities and the definition of net debt was amended to exclude those securities. If the FELINE PACS were included in consolidated net worth at December 31, 2001, Williams' ratio of net debt to consolidated net worth plus net debt would have been 57.6 percent. None of the Williams loans, notes or debentures maintains preferential rights in the event of liquidation.

Terms of certain subsidiaries' borrowing arrangements with lenders limit the transfer of funds to Williams (Parent). At December 31, 2001, approximately $423 million of net assets of consolidated subsidiaries was restricted. In addition, certain equity method investees' borrowing arrangements and foreign government regulations limit the amount of dividends or distributions to Williams. Restricted net assets of equity method investees was approximately $337 million at December 31, 2001.

Aggregate minimum maturities, considering the reclassification of current obligations as previously described, for each of the next five years are as follows:

	(MILLIONS)
2002	$1,037
2003	732
2004	1,562
2005	282
2006	1,156

Cash payments for interest (net of amounts capitalized) are as follows: 2001 -- $643 million; 2000 -- $648 million; and 1999 -- $512 million.

LEASES-LESSEE

Future minimum annual rentals under noncancelable operating leases as of December 31, 2001, are payable as follows:

	(MILLIONS)
2002	$ 81.7
2003	57.8
2004	47.0
2005	37.2
2006	28.6
Thereafter	176.7
Total	$429.0

Total rent expense was $112 million in 2001, $107 million in 2000 and $109 million in 1999.

During 2000, Williams entered into operating lease agreements with two special purpose entities (SPEs) owned by third parties covering certain Williams travel center stores, offshore oil and gas pipelines and an onshore gas processing plant. The SPEs are not consolidated by Williams as their equity is provided by non-related parties. The total estimated cost of the assets covered by the lease agreements is approximately $300 million. The lease terms include a five-year base term including the construction phase and can be renewed for another five-year term upon mutual agreement of the lessor and lessee.

Williams has an option to purchase the leased assets during the lease terms at amounts approximating the lessors' cost. Williams provides a residual value guarantee equal to 85 percent of the lessor's cost on the completed travel center stores and equal to 89.9 percent of the lessor's cost, less the present value of actual lease payments, on the offshore oil and gas pipelines and the onshore gas processing plant. In the event that Williams does not exercise its purchase option, Williams expects the fair market value of the covered assets to substantially offset Williams' obligation under the residual value guarantees. Williams' disclosures for future minimum annual rentals under noncancelable operating leases do not include amounts for residual value guarantees. As of December 31, 2001, approximately $276 million of costs has been incurred by the lessors.

LEASES-LESSOR

In third-quarter 2001, Williams purchased the Technology Center and three corporate aircraft from WCG for $276 million, which represents the approximate actual cost of construction of the Williams Technology Center and the acquisition cost of the ancillary assets and aircraft. Williams then entered into long-term lease arrangements under which WCG is the sole lessee of the Technology Center and aircraft assets. The lease arrangements are fully backed by the underlying assets and have payment terms ranging from three to ten years. WCG has an option to purchase the Technology Center, at any time during the term of the lease, at the unamortized cost of those assets. Williams has a put option that requires WCG to purchase the Technology Center due to a default by WCG on the lease at the unamortized cost of the assets plus accrued rent, or within the 90-day period prior to the 10-year lease termination or in the event of a casualty loss which exceeds set amounts at the unamortized cost of the Technology Center. WCG also has an option to purchase the corporate aircraft, at any time during the term of the lease, at the greater of the unamortized cost or the market value of those assets. The leases are classified as direct-financing leases. As a result, Williams removed the leased assets discussed above from its books and recorded a minimum lease payment receivable equal to the total of the minimum lease payments of $396 million reduced by the unearned interest income which is computed using a variable interest rate and initially equaled $120 million. Lease payments from WCG are applied as a reduction of the receivable while the unearned income is accreted to interest income using the effective interest method over the life of the leases. As of December 31, 2001, the Consolidated Balance Sheet includes $28.8 million in current accounts and notes receivable and $137.2 million (net of allowance for doubtful accounts of $103.2 million) in noncurrent other assets and deferred charges relating to these leasing arrangements.

Future minimum lease payments receivable under the leasing arrangements as of December 31, 2001, are as follows:

	(MILLIONS)
2002	$ 41.9
2003	40.6
2004	36.4
2005	27.1
2006	24.8
Thereafter	204.5
Total minimum lease payments receivable	375.3
Less: Unearned income	(106.1)
Allowance for doubtful accounts	(103.2)
Recorded net minimum lease payments receivable	$ 166.0

NOTE 14. PREFERRED INTERESTS IN CONSOLIDATED SUBSIDIARIES

Williams owns the controlling interest in various entities formed in separate transactions that resulted in the sale of a non-controlling preferred ownership interest in one entity in each transaction to an outside investor. The assets and liabilities of each of these entities are included in the Consolidated Balance Sheet. The preferred ownership interest in each entity is reflected in the preferred interest in consolidated subsidiaries caption of the Consolidated Balance Sheet. The outside investors in these entities are unconsolidated special purpose entities formed solely for the purpose of purchasing the preferred ownership interest in the respective entity and are capitalized with no less than three-percent equity from an independent third party. Each outside investor is entitled to a priority return paid from the operating results of the entity in which they have an investment. Williams has the option to acquire each outside investor's interest in each entity for an amount approximating the fair value of their ownership interest. Absent the occurrence of certain events, the purchase option can be exercised at any time prior to the expiration of the initial priority return period.

In addition to financial support in favor of these entities, typically in the form of demand notes, Williams provides the outside investor in each entity with certain assurances that the entities involved in each transaction will maintain certain financial ratios and follow various restrictive covenants similar to, but in some cases broader than those found in Williams' credit agreements. A violation of any restrictive covenant, a default by Williams of its debt obligations, a failure to make priority distributions, or a failure to negotiate new priority return structures prior to the end of the initial priority return structure period, could ultimately result in an election by the outside investor in the impacted entity to liquidate the assets of that entity. A liquidation could result in a demand of repayment on any Williams obligations as well as the sale of other assets owned or secured by the entity in order to generate proceeds to return the investor's capital account balance. Williams can prevent liquidation of each entity through the exercise of the option to purchase the outside investor's preferred ownership interest.

At December 31, 2001, outside investors owned preferred interests in the following Williams subsidiaries.

SNOW GOOSE ASSOCIATES, L.L.C.

In December 2000, Williams formed two separate legal entities, Snow Goose Associates, L.L.C. (Snow Goose) and Arctic Fox Assets, L.L.C. (Arctic Fox) for the purpose of generating funds to invest in certain Canadian energy-related assets. An outside investor contributed $560 million in exchange for the non-controlling preferred interest in Snow Goose. The investor in Snow Goose is entitled to quarterly priority distributions, representing an adjustable rate structure of approximately 3.5 percent at December 31, 2001. The initial priority return period is currently set to expire in December 2005.

Snow Goose loaned the proceeds received from the outside investor to Arctic Fox. These proceeds were ultimately used to purchase the Canadian energy-related assets. Snow Goose's sole asset consists of a note receivable, due in December 2005 from Arctic Fox. At December 31, 2001, the assets of Arctic Fox include approximately a $400 million note receivable from Williams Energy (Canada), Inc., due in December 2005, collateralized by the Canadian energy-related assets, $35 million in loans from Williams payable upon demand, an investment in operating assets with a carrying value of approximately $140 million and an investment in 342,000 shares of Williams' cumulative convertible preferred stock with a liquidation value of $1,000 per share. If sold in a liquidation, each share of the Williams' cumulative preferred stock would become convertible into a number of Williams common stock determined by dividing $1,000 by a conversion price. The initial conversion price is $31.8125 per share. The initial conversion price is subject to adjustment for events such as stock splits of Williams common stock, the issuance of stock dividends, issuance of below market value subscription rights or warrants, and issuance of unusually large cash dividends.

In addition to the covenants discussed above, the Snow Goose transaction requires Williams to maintain a credit rating equal to or higher than BBB- by Standard & Poor's or a credit rating equal to or higher than Baa3 by Moody's Investor's Service, but Williams must also maintain credit ratings of BB+ by Standard & Poor's and Ba1 by Moody's Investor's Service regardless of the rating by the other agency. Other significant covenants include: (i) an obligation of Williams Energy (Canada), Inc. to have earnings before interest, taxes, depreciation and amortization each quarter that are at least three times greater than the interest due on its loan from Arctic Fox for the quarter; (ii) an obligation of Williams Energy (Canada), Inc. to have total debt that is less than 50 percent of its total capitalization; (iii) an obligation of Arctic Fox to have assets with a book value that is at least two times larger than the unrecovered capital of the outside investor in Snow Goose; and (iv) an obligation of Arctic Fox to have cash flow each quarter that is at least three times greater than amounts payable to the outside investor in Snow Goose for that quarter.

CASTLE ASSOCIATES L.P.

In December 1998, Williams formed Castle Associates L.P. (Castle) through a series of transactions that resulted in the sale of a non-controlling preferred interest in Castle to an outside investor for $200 million. Williams used the proceeds of the sale for general corporate purposes. At December 31, 2001, the assets of Castle include approximately $145 million in loans from Williams payable upon demand (demand loans), a $125 million loan from a Williams subsidiary secured by operating assets and a Williams guarantee due in December 2003, $60 million in third-party receivables guaranteed by Williams, and approximately $204 million in other various assets. While no event of default would arise from a downgrade of Williams' unsecured credit rating below Baa3 by Moody's Investor's Service and below BBB- by Standard & Poor's, Williams would be required to replace the demand loans with other assets. The outside investor is entitled to quarterly priority distributions based upon an adjustable rate structure of approximately 3.8 percent at December 31, 2001, in addition to a portion of the participation in the operating results of Castle. The initial priority return structure is currently set to expire in December 2002.

Castle must satisfy certain financial covenants beyond those found in Williams' standard credit agreements, including a requirement that it must have assets with a value of at least 1.75 times the outside investors contributed capital, and a requirement that at the end of each fiscal quarter, Castle's profits for the year to date be at least 1.4 times the investor's priority return.

PICEANCE PRODUCTION HOLDINGS LLC

In December 2001, Williams formed Piceance Production Holdings LLC (Piceance) and Rulison Production Company LLC (Rulison) in a series of transactions that resulted in the sale of a non-controlling preferred interest in Piceance to an outside investor for $100 million. Williams used the proceeds of the sale for general corporate purposes. The assets of Piceance include fixed-price overriding royalty interests in certain oil and gas properties owned by a Williams subsidiary as well as a $135 million note from Rulison. The outside investor is entitled to monthly priority distributions beginning in January 2002, based upon an adjustable rate structure currently approximating 3.9 percent in addition to participation in a portion of the operating results of Piceance. The initial priority return structure is currently scheduled to expire in December 2006.

Piceance must satisfy certain financial covenants beyond those found in Williams' standard credit agreements, including a requirement that it have assets with a value of at least 1.35 times the investor's capital account, and a requirement that at the end of each fiscal quarter, Piceance's profits for the year to date be at least 1.2 times the investor's priority return.

Williams is allowed to access the excess cash flow of Piceance and Rulison between distribution period through demand loans. However, if Williams' credit ratings fall below BBB- by Standard & Poor's and Baa3 by Moody's Investor's Service or below BB+ by Standard & Poor's or below Ba1 by Moody's Investor's Service, Williams will be prevented from using demand loans, and therefore excess cash will be retained between distribution periods. These ratings triggers do not force an acceleration.

Failure to satisfy the terms of the agreements would entitle the investor to deliver a transfer notice declaring the occurrence of a transfer event. In such case, unless the Williams' subsidiary that is a member of Piceance exercises its purchase option, the managing member interest will automatically be transferred to the investor ten days following the transfer event. Upon a transfer event, the managing member can elect to liquidate and wind-up Piceance.

In addition to the transactions discussed above, an outside investor owns a non-controlling preferred interest in the following Williams subsidiary.

WILLIAMS RISK HOLDINGS L.L.C.

During 1998, Williams formed Williams Risk Holdings L.L.C. (Holdings) in a series of transactions that resulted in the sale of a non-controlling preferred interest in Holdings to an outside investor for $135 million. Williams used the proceeds from the sale for general corporate purposes. The outside investor in Holdings is not a special purpose entity. The outside investor is entitled to monthly preferred distributions based upon an adjustable rate structure of approximately 5.9 percent at December 31, 2001, in addition to participation in a portion of the operating results of Holdings. The initial priority return structure of Holdings is currently scheduled to expire in September 2003 at which time Williams can attempt to negotiate a new priority return or elect to retire the outside investor's interest. In addition, terms of the Holdings transaction require Williams to maintain a specified minimum credit rating with various ratings organizations. Violation of various restrictive covenants, including a downgrade of Williams' senior unsecured rating below BB by Standard & Poor's or Ba1 by Moody's Investor's Service, could require an early retirement of the outside investor's ownership interest.

Holdings must satisfy certain financial covenants beyond those found in Williams standard credit agreements, including, (i) a requirement that Holdings' cash, promissory notes and investments minus its contingent liabilities be equal to or greater than the purchase price of the outside investors' interests; (ii) a requirement that Holdings' maintain a consolidated net worth at least two times greater than the purchase price of the outside investors' interests; and (iii) a requirement that Holdings' subsidiary's assets exceed by at least 1.05 times the fair market value of such subsidiary's liabilities.

NOTE 15. WILLIAMS OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF TRUST HOLDING ONLY WILLIAMS INDENTURES

In December 1999, Williams formed Williams Capital Trust I which issued $175 million in zero coupon Williams obligated mandatorily redeemable preferred securities. During April 2001, these securities were redeemed.

NOTE 16. STOCKHOLDERS' EQUITY

In January 2001, Williams issued approximately 38 million shares of common stock in a public offering at $36.125 per share. The impact of this issuance resulted in increases of approximately $38 million to common stock and $1.3 billion to capital in excess of par value.

During 1999, each remaining share of the $3.50 Williams preferred stock was converted at the option of the holder into 4.6875 shares of Williams common stock prior to the redemption date.

Williams maintains a Stockholder Rights Plan under which each outstanding share of Williams common stock has one-third of a preferred stock purchase right attached. Under certain conditions, each right may be exercised to purchase, at an exercise price of $140 (subject to adjustment), one two-hundredth of a share of Series A Junior Participating Preferred Stock. The rights may be exercised only if an Acquiring Person acquires (or obtains the right to acquire) 15 percent or more of Williams common stock; or commences an offer for 15 percent or more of Williams common stock; or the board of directors determines an Adverse Person has become the owner of a substantial amount of Williams common stock. The rights, which until exercised do not have voting rights, expire in 2006 and may be redeemed at a price of $.01 per right prior to their expiration, or within a specified period of time after the occurrence of certain events. In the event a person becomes the owner of more than 15 percent of Williams common stock or the board of directors determines that a person is an Adverse Person, each holder of a right (except an Acquiring Person or an Adverse Person) shall have the right to receive, upon exercise, Williams common stock having a value equal to two times the exercise price of the right. In the event Williams is engaged in a merger, business combination or 50 percent or more of Williams' assets, cash flow or earnings power is sold or transferred, each holder of a right (except an Acquiring Person or an Adverse Person) shall have the right to receive, upon exercise, common stock of the acquiring company having a value equal to two times the exercise price of the right.

NOTE 17. STOCK-BASED COMPENSATION

Williams has several plans providing for common-stock-based awards to employees and to non-employee directors. The plans permit the granting of various types of awards including, but not limited to, stock options, stock-appreciation rights, restricted stock and deferred stock. Awards may be granted for no consideration other than prior and future services or based on certain financial performance targets being achieved. The purchase price per share for stock options and the grant price for stock-appreciation rights may not be less than the market price of the underlying stock on the date of grant. Depending upon terms of the respective plans, stock options generally become exercisable in one-third increments each year from the anniversary of the grant or after three or five years, subject to accelerated vesting if certain future stock prices or if specific financial performance targets are achieved. Stock options expire 10 years after grant. At December 31, 2001, 46.4 million shares of Williams common stock were reserved for issuance pursuant to existing and future stock awards, of which 18.2 million shares were available for future grants (20.9 million at December 31, 2000).

Certain of these plans had loan programs that provided loans for either a three- or five-year term using stock certificates as collateral. Interest payments are due annually during the term of the loan and interest rates are based on the minimum applicable federal rates required to avoid imputed income. The principal amount is due at the end of the loan term. Participants who leave the company during the loan period are required to pay the loan balance and any accrued interest within 30 days of termination. The amount of loans outstanding at December 31, 2001 and 2000, totaled approximately $38.1 million and $53.5 million, respectively.

Effective November 14, 2001, the Company will no longer issue new loans under the stock option loan program. Current loan holders have been offered a one-time opportunity to refinance outstanding loans at a market rate of interest commensurate with the borrower's credit standing. The refinancing, if elected, would be in the form of a full recourse note, interest payable annually in cash, and loan maturity of no later than December 31, 2005. The loan would remain in force until maturity in the event of the employee's termination. The Company would hold the collateral shares and would review the borrower's financial position upon the one-time election and on an annual basis thereafter. If a current loan holder does not make the election to refinance, the current loans would remain outstanding with no refinancing at maturity.

The following summary reflects stock option activity for Williams common stock and related information for 2001, 2000 and 1999:

	2001		2000		1999	
	OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE	OPTIONS	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding -- beginning of year	23.1	$28.63	22.8	$25.03	21.7	$20.73
Granted	4.8	37.45	3.8	45.87	5.1	39.62
Exercised	(3.3)	18.47	(3.3)	23.12	(3.7)	18.81
Barrett option conversions (Note 2)	2.0	21.57	--	--	--	--
Adjustment for WCG spinoff(1)	2.1	--	--	--	--	--
Canceled	(3.1)	32.35	(.2)	38.19	(.3)	36.50
Outstanding -- end of year	25.6	$28.23	23.1	$28.63	22.8	$25.03
Exercisable at end of year	20.0	$26.41	22.1	$28.24	21.9	$24.50

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(1) Effective with the spinoff of WCG on April 23, 2001, the number of unexercised Williams stock options and the exercise price were adjusted to preserve the intrinsic value of the stock options that existed prior to the spinoff.

The following summary provides information about Williams stock options outstanding and exercisable at December 31, 2001:

	STOCK OPTIONS OUTSTANDING			STOCK OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	OPTIONS (MILLIONS)	WEIGHTED-AVERAGE EXERCISE PRICE	WEIGHTED-AVERAGE REMAINING CONTRACTUAL LIFE	OPTIONS (MILLIONS)	WEIGHTED-AVERAGE EXERCISE PRICE
$4.24 to $25.14	10.2	$16.39	3.9 years	10.2	$16.39
$26.79 to $42.52	15.4	36.03	7.5 years	9.8	36.78
Total	25.6	$28.23	6.1 years	20.0	$26.41

The estimated fair value at date of grant of options for Williams common stock granted in 2001, 2000 and 1999, using the Black-Scholes option pricing model, is as follows:

	2001	2000	1999
Weighted-average grant date fair value of options for Williams common stock granted during the year	$10.93	$15.44	$11.90
Assumptions:			
Dividend yield	1.9%	1.5%	1.5%
Volatility	35%	31%	28%
Risk-free interest rate	4.8%	6.5%	5.6%
Expected life (years)	5.0	5.0	5.0

Pro forma net income (loss) and earnings per share, assuming Williams had applied the fair-value method of SFAS No. 123, "Accounting for Stock-Based Compensation" in measuring compensation cost beginning with 1997 employee stock-based awards, are as follows:

	2001		2000		1999	
	PRO FORMA	REPORTED	PRO FORMA	REPORTED	PRO FORMA	REPORTED
	(MILLIONS, EXCEPT PER-SHARE AMOUNTS)					
Net income (loss)	$(488.8)	$(477.7)	$381.4	$524.3	$168.1	$221.4
Earnings (loss) per share:						
Basic	$ (.98)	$ (.96)	$ .86	$ 1.18	$ .38	$ .50
Diluted	$ (.98)	$ (.95)	$ .85	$ 1.17	$ .37	$ .50

Pro forma amounts for 2001 include compensation expense from certain Williams awards made in 1999 and compensation expense from Williams awards made in 2001.

Pro forma amounts for 2000 include compensation expense from certain Williams awards made in 1999 and the total compensation expense from Williams awards made in 2000, as these awards fully vested in 2000 as a result of the accelerated vesting provisions. Pro forma amounts for 2000 include $37.3 million for Williams awards and $105.7 million related to discontinued operations.

Pro forma amounts for 1999 include the remaining total compensation expense from Williams awards made in 1998 and the total compensation expense from certain Williams awards made in 1999, as these awards fully vested in 1999 as a result of the accelerated vesting provisions. In addition, 1999 pro forma amounts include compensation expense related to the WCG plan awards and conversions in 1999. Pro forma amounts for 1999 include $47.1 million related to Williams awards and $6.2 million related to discontinued operations. Since compensation expense from stock options is recognized over the future years' vesting period for pro forma disclosure purposes, and additional awards generally are made each year, pro forma amounts may not be representative of future years' amounts.

Williams granted deferred shares of approximately 1,423,000 in 2001, 332,000 in 2000 and 260,000 in 1999. Deferred shares are valued at the date of award, and the weighted-average grant date fair value of the shares granted was $40.84 in 2001, $39.13 in 2000 and $34.84 in 1999. Approximately $22 million, $11 million and $13 million was recognized as expense for deferred shares of Williams in 2001, 2000 and 1999, respectively. Expense related to deferred shares is recognized in the performance year or over the vesting period, depending on the terms of the awards. Williams issued approximately 260,000 in 2001, 140,000 in 2000 and 125,000 in 1999, of the deferred shares previously granted.

NOTE 18. FINANCIAL INSTRUMENTS, DERIVATIVES, INCLUDING ENERGY TRADING ACTIVITIES, AND CONCENTRATION OF CREDIT RISK

FINANCIAL INSTRUMENTS FAIR VALUE

Fair-value methods

The following methods and assumptions were used by Williams in estimating its fair-value disclosures for financial instruments:

Cash and cash equivalents and notes payable: The carrying amounts reported in the balance sheet approximate fair value due to the short-term maturity of these instruments.

Retained interest in accounts receivable sold to SPEs: The carrying amounts reported in the balance sheet approximate fair value. Fair value is based on the present value of future expected cash flows using management's best estimates of various factors, including credit loss experience and discount rates commensurate with the risks involved.

Notes and other noncurrent receivables, margin deposits and deposits received from customers relating to energy trading and hedging activities: For those instruments with interest rates approximating market or maturities of less than three years, fair value is estimated to approximate historically recorded amounts.

Investments-cost and advances to affiliates: Fair value is reflected to approximate historically recorded amounts as the investments are primarily in non-publicly traded foreign companies for which it is not practicable to estimate fair value of these investments.

Investment in WCG: Fair value is calculated based on the year-end closing price of WCG common stock. The carrying amount reflects write-downs of the WCG investment to zero (see Note 4).

Ferrellgas Partners L.P. senior common units: These securities are classified as available-for-sale and are reported at fair value, with net unrealized appreciation or depreciation reported as a component of accumulated other comprehensive income.

Long-term debt: The fair value of Williams' long-term debt is valued using indicative year-end traded bond market prices for publicly traded issues, while private debt is valued based on the prices of similar securities with similar terms and credit ratings. At December 31, 2001 and 2000, 75 percent and 59 percent, respectively, of Williams' long-term debt was publicly traded. Williams used the expertise of outside investment banking firms to assist with the estimate of the fair value of long-term debt.

Williams obligated mandatorily redeemable preferred securities of Trust: Fair value is based on the prices of similar securities with similar terms and credit ratings as the preferred securities are not publicly traded. Williams used the expertise of an outside investment banking firm to establish the fair value of obligated mandatorily redeemable preferred securities.

Interest-rate swaps: Fair value is determined by discounting estimated future cash flows using forward-interest rates derived from the year-end yield curve. Fair value was calculated by the financial institutions that are the counterparties to the swaps.

Foreign exchange forward contract: Fair value is determined by discounting estimated future cash flows using forward foreign exchange rates derived from the year-end forward exchange curve. Fair value was calculated by the financial institution that is counterparty to the agreement.

Energy risk management and trading and hedging contracts: Energy contracts utilized in trading activities include forward contracts, futures contracts, option contracts, swap agreements, commodity inventories, short- and long-term purchase and sale commitments, which involve physical delivery of an energy commodity and energy-related contracts, such as transportation, storage, full requirements, load serving and power tolling contracts. In addition, Williams enters into interest-rate swap agreements and credit default swaps to manage the interest rate and credit risk in its energy trading portfolio. Fair value of energy contracts is determined based on the nature of the transaction and the market in which transactions are executed. Certain transactions are executed in exchange-traded or over-the-counter markets for which quoted prices in active periods exist. Transactions are executed in exchange-traded or over-the-counter markets for which quoted market prices may exist; however, the markets may be relatively inactive, and price transparency is limited. Certain transactions are executed for which quoted market prices are not available. See Note 1 regarding Energy commodity risk management and trading activities and Derivative instruments and hedging activities for further discussion about determining fair value for energy contracts.

Carrying amounts and fair values of Williams' financial instruments and energy risk management and trading activities

ASSET (LIABILITY)	2001 CARRYING AMOUNT	2001 FAIR VALUE	2000 CARRYING AMOUNT	2000 FAIR VALUE
	(MILLIONS)			
Financial instruments:				
Cash and cash equivalents	$ 1,301.1	$ 1,301.1	$ 996.8	$ 996.8
Retained interest in accounts receivable sold to SPEs	205.0	205.0	936.4	936.4
Notes and other noncurrent receivables	41.2	41.2	67.3	67.3
Investments-cost and advances to affiliates	383.5	383.5	407.7	407.7
Investment in WCG	--	49.8	--	--
Ferrellgas Partners L.P. senior common units	--	--	193.9	193.9
Notes payable	(1,424.5)	(1,424.5)	(2,036.7)	(2,036.7)
Long-term debt, including current portion	(10,528.2)	(10,710.7)	(8,464.6)	(8,522.3)
Williams obligated mandatorily redeemable preferred securities of Trust	--	--	(189.9)	(191.6)
Margin deposits	213.8	213.8	730.9	730.9
Deposits received from customers relating to energy risk management and trading and hedging activities	(265.5)	(265.5)	(244.6)	(244.6)
Guarantees	(13.2)	(a)	(17.0)	(a)
Derivatives, including energy risk management and trading activities:				
Energy risk management and trading activities:				
Assets	10,723.5	10,723.5	9,710.9	9,710.9
Liabilities	(8,462.3)	(8,462.3)	(8,900.1)	(8,900.1)
Energy commodity cash flow and fair-value hedges:				
Assets	488.9	488.9	--	65.9
Liabilities	(28.1)	(28.1)	(2.5)	(218.1)
Other energy commodity derivatives:				
Assets	--	--	--	--
Liabilities	(11.8)	(11.8)	--	--
Foreign currency hedges	16.9	16.9	--	--
Interest-rate derivatives(b)	--	--	(32.8)	(32.8)

(a) It is not practicable to estimate the fair value of these financial instruments because of their unusual nature and unique characteristics.

(b) At December 31, 2001, Williams had interest rate swaps to mitigate its interest rate risk in its energy trading portfolio and are included in energy risk management and trading and price-risk management activities.

Other financial instruments

Williams, through wholly owned bankruptcy remote subsidiaries, sells certain trade accounts receivable to special purpose entities (SPEs) in a securitization structure requiring annual renewal. Williams acts as the servicing agent for sold receivables and receives a servicing fee approximating the fair value of such services.

At December 31, 2001, approximately $625 million of accounts receivable that would otherwise be Williams receivables were sold to the SPEs in exchange for $420 million in cash and a $205 million subordinated retained interest in the accounts receivable sold to the SPEs. In 2000, Williams sold accounts receivable to special purpose entities under a similar structure. For 2001 and 2000, Williams received cash from the SPEs of approximately $12.8 billion and $9 billion, respectively. The sales of these receivables resulted in a charge to results of operations of approximately $17 million and $23 million in 2001 and 2000, respectively. The retained interest in accounts receivable sold to the SPEs is subject to credit risk to the extent that these receivables are not collected. See Concentration of credit risk below.

In addition to the guarantees included in the table, the guarantees and payment obligations related to WCG discussed in Note 3, certain residual value guarantees discussed in Note 13 and potential obligation under a put agreement discussed in Note 4, Williams has issued other guarantees and letters of credit with off balance sheet risk that total approximately $99 million and $78 million at December 31, 2001 and 2000, respectively. Williams believes it will not have to perform under these other guarantees and letters of credit, because the likelihood of default by the primary party is remote and/or because of certain indemnifications received from other third parties.

DERIVATIVES, INCLUDING ENERGY RISK MANAGEMENT AND TRADING ACTIVITIES

Energy risk management and trading activities

Williams, through Energy Marketing & Trading, has energy commodity risk management and trading operations that enter into energy contracts to provide price-risk management services associated with the energy industry to its customers. Contracts utilized in energy commodity risk management and trading activities include forward contracts, futures contracts, option contracts, swap agreements, short- and long-term purchase and sale commitments which involve physical delivery of an energy commodity and energy-related contracts, including transportation, storage, full requirements, load serving and power tolling contracts. In addition, Williams enters into interest rate swap agreements and credit default swaps to manage the interest rate and credit risk in its energy portfolio. See Note 1 for a description of the accounting valuation for these energy commodity risk management and trading activities. The net gain recognized in revenues from all price-risk management and trading activities was $1,696 million, $1,285.1 million and $214 million in 2001, 2000 and 1999, respectively.

Energy Marketing & Trading actively manages the risk assumed from its activities and operations. This risk results from exposure to commodity market prices, volatility in those prices, correlation of commodity prices, the liquidity of the market in which the contract is transacted, interest rates, credit and counterparty performance. Energy Marketing & Trading manages market risk on a portfolio basis through established trading policy guidelines which are monitored on a daily basis. Energy Marketing & Trading actively seeks to diversify its portfolio in managing the commodity price risk in the transactions that it executes in various markets and regions by executing offsetting contracts to manage such commodity price risk.

Futures contracts are commitments to either purchase or sell a commodity at a future date for a specified price and are generally settled in cash, but may be settled through delivery of the underlying commodity. An exchange-traded or over-the-counter market for which quoted prices in active periods are available exists for the futures contracts entered into by Energy Marketing & Trading. The fair value of these contracts is based on quoted prices.

Swap agreements call for Energy Marketing & Trading to make payments to (or receive payments from) counterparties based upon the differential between a fixed and variable price or variable prices of energy commodities for different locations. Forward contracts and purchase and sale commitments with fixed volumes which involve physical delivery of energy commodities, contain both fixed and variable pricing terms. Swap agreements, forward contracts and purchase and sale commitments with fixed volumes are valued based on prices of the underlying energy commodities over the contract life and contractual or notional volumes with the resulting expected future cash flows discounted to a present value using a risk-free market interest rate.

Certain of Energy Marketing & Trading's purchase and sale commitments, which involve physical delivery of energy commodities, contain optionality clauses or other arrangements that result in varying volumes. In addition, Energy Marketing & Trading buys and sells physical and financial option contracts which give the buyer the right to exercise the option and receive the difference between a predetermined strike price and a market price at the date of exercise. These contracts are valued based on option pricing models considering prices of the underlying energy commodities over the contract life, volatility of the commodity prices, contractual volumes, estimated volumes under option and other arrangements and a risk-free market interest rate.

Energy-related contracts include transportation, storage, full requirements, load serving and power tolling contracts. Transportation contracts provide Energy Marketing & Trading the right, but not the obligation, to transport physical quantities of natural gas from one location to another on a daily basis. The payment or settlement required typically has a fixed component paid regardless of whether the transportation capacity is used and a variable component. Variable payments are made for shipments actually made during the month. The decision to use the capacity to ship natural gas is based on the difference between the price of natural gas at the pipeline receipt and delivery locations and the variable cost of transportation. Storage contracts provide Energy Marketing & Trading the right, but not the obligation, to store physical quantities of gas to take advantage of anticipated differentials between the price of natural gas during the period between injection and withdrawal and to enable it to supply existing delivery commitments when the estimated price spread differential less the cost of storing the natural gas is favorable. Energy Marketing & Trading enters full requirements arrangements which are structured to meet a variety of customers' needs. Agreements may be designed to manage natural gas and power supply requirements, service load growth, manage unplanned outages or other scenarios. Load serving agreements require Energy Marketing & Trading to procure energy supplies for its customers necessary to meet their load or energy needs. Power tolling contracts provide Energy Marketing & Trading the right, but not the obligation, to call on the counterparty to convert natural gas to electricity at a predefined heat conversion rate. Energy Marketing & Trading supplies the natural gas to the power plants and markets the electricity output. In exchange for this right, Energy Marketing & Trading pays a monthly fee and a variable fee based on usage. The decision as to whether the option will be exercised is dependent on the differential between natural gas and power commodity prices considering the heat conversion rate and variable fee.

Fair value of these energy-related contracts is estimated using valuation techniques that incorporate option pricing theory, statistical and simulation analysis, present value concepts incorporating risk from uncertainty of the timing and amount of estimated cash flows and specific contractual terms. These valuation techniques utilize factors such as quoted energy commodity market prices, estimates of energy commodity market prices in the absence of quoted market prices, volatility factors underlying the positions, estimated correlation of energy commodity prices, contractual volumes, estimated volumes under option and other arrangements, the liquidity of the market in which the contract is transacted and a risk-free market discount rate. Fair value also reflects a risk premium that market participants would consider in their determination of fair value.

Interest-rate swap agreements are used to manage the interest rate risk in the energy trading portfolio. Under these agreements, Energy Marketing & Trading pays a fixed rate and receives a variable rate on the notional amount of the agreements. The fair value of these contracts is determined by discounting estimated future cash flows using forward interest rates derived from interest rate yield curves. Credit default swaps are used to manage counterparty credit exposure in the energy trading portfolio. Under these agreements, Energy Marketing & Trading pays a fixed rate premium for a notional amount of risk coverage associated with certain credit events. The covered credit events are bankruptcy, obligation acceleration, failure to pay and restructuring. The fair value of these agreements is based on current pricing received from the counterparties.

The valuation of the contracts entered into by Energy Marketing & Trading also considers factors such as the liquidity of the market in which the contract is transacted, uncertainty regarding the ability to liquidate the position considering market factors applicable at the date of such valuation and risk of non-performance and credit considerations of the counterparty. For contracts or transactions that extend into periods for which actively quoted prices are not available, Energy Marketing & Trading estimates energy commodity prices in the illiquid periods by incorporating information obtained from commodity prices in actively quoted markets, prices reflected in current transactions and market fundamental analysis.

Determining fair value for contracts also involves complex assumptions including estimating natural gas and power market prices in illiquid periods and markets, estimating volatility and correlation of natural gas and power prices, evaluating risk from uncertainty inherent in estimating cash flows and estimates regarding counterparty performance and credit considerations.

Energy Marketing & Trading has the risk of loss as a result of counterparties not performing pursuant to the terms of their contractual obligations. Risk of loss can result from credit considerations and the regulatory environment of the counterparty. Energy Marketing & Trading attempts to minimize credit-risk exposure to trading counterparties and brokers through formal credit policies, consideration of credit ratings from public rating agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. In addition, Williams has entered into credit default swaps to reduce this exposure. Valuation allowances are provided for credit risk in accordance with established credit policies.

The concentration of counterparties within the energy and energy trading industry impacts Williams' overall exposure to credit risk in that these counterparties are similarly influenced by changes in the economy and regulatory issues.

The counterparties associated with assets from energy commodity risk management and trading activities as of December 31, 2001 and 2000, are summarized as follows:

	2001		2000	
	INVESTMENT GRADE(A)	TOTAL	INVESTMENT GRADE(A)	TOTAL
	(MILLIONS)			
Gas and electric utilities	$ 4,253.9	$ 4,924.5	$ 3,281.1	$3,495.2
Energy marketers and traders	5,645.5	6,058.2	4,105.9	4,861.0
Financial institutions	249.8	341.7	674.6	677.2
Other	16.4	47.3	297.1	738.4
Total	$10,165.6	$11,371.7	$ 8,358.7	9,771.8
Credit reserves		(648.2)		(60.9)
Assets from price-risk management activities(b)		$10,723.5		$9,710.9

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(a) "Investment Grade" is primarily determined using publicly available credit ratings along with consideration of cash, standby letters of credit, parent company guarantees and property interests, including oil and gas reserves. Included in "Investment Grade" are counterparties with a minimum Standard & Poor's or Moody's Investor's Service rating of BBB- or Baa3, respectively.

(b) One counterparty within the California power market represents greater than ten percent of assets from energy risk management and trading activities and is included in "investment grade." Standard & Poor's or Moody's Investor's Service does not rate this counterparty. However, Energy Marketing & Trading has considered this counterparty investment grade by the manner in which it was established by the State of California.

The notional quantities for trading activities for the prior year, December 31, 2000, as required under previous accounting disclosure rules, were as follows:

	2000	
	PAYOR	RECEIVER
Fixed price:		
Natural gas (Tbtu)	4,552.4	6,406.3
Refined products, NGLs and crude (MMbbls)	450.8	300.9
Power (Terawatt Hrs)	440.0	207.1
Variable price:		
Natural gas (Tbtu)	2,715.5	2,473.5
Refined products, NGLs and crude (MMbbls)	44.2	63.2

The net cash inflows related to these contracts at December 31, 2000 were approximately $1 billion. At December 31, 2000, the cash inflows extend primarily through 2022.

Energy commodity cash flow hedges

Williams is also exposed to market risk from changes in energy commodity prices within the Energy Services business unit and the non-trading operations of Energy Marketing & Trading. Williams utilizes derivatives to manage its exposure to the variability in expected future cash flows attributable to commodity price risk associated with forecasted purchases and sales of natural gas, refined products, crude oil, electricity, ethanol and corn. These derivatives have been designated as cash flow hedges.

Williams produces, buys and sells natural gas at different locations throughout the United States. To reduce exposure to a decrease in revenues or an increase in costs from fluctuations in natural gas market prices, Williams enters into natural gas futures contracts and swap agreements to fix the price of anticipated sales and purchases of natural gas.

Williams' refineries purchase crude oil for processing and sell the refined products. To reduce the exposure to increasing costs of crude oil and/or decreasing refined product sales prices due to changes in market prices, Williams enters into crude oil and refined products futures contracts and swap agreements to lock in the prices of anticipated purchases of crude oil and sales of refined products.

Williams' electric generation facilities utilize natural gas in the production of electricity. To reduce the exposure to increasing costs of natural gas due to changes in market prices, Williams enters into natural gas futures contracts and swap agreements to fix the prices of anticipated purchases of natural gas. To reduce the exposure to decreasing revenues from electricity sales, Williams enters into fixed-price forward physical contracts to fix the prices of anticipated sales of electric production.

Derivative gains or losses from these cash flow hedges are deferred in other comprehensive income and reclassified into earnings in the same period or periods during which the hedged forecasted purchases or sales affect earnings. To match the underlying transaction being hedged, derivative gains or losses associated with anticipated purchases are recognized in costs and operating expenses and amounts associated with anticipated sales are recognized in revenues in the Consolidated Statement of Operations. Approximately $1 million of gains from hedge ineffectiveness is included in revenues in the Consolidated Statement of Operations during 2001. There were no derivative gains or losses excluded from the assessment of hedge effectiveness and no hedges were discontinued during 2001 as a result of it becoming probable that the forecasted transaction will not occur. There is approximately $142 million of pre-tax gains related to terminated derivatives included in accumulated other comprehensive income at December 31, 2001. These amounts will be recognized into net income as the hedged transaction occurs. As of December 31, 2001, Williams has hedged future cash flows associated with anticipated energy commodity purchases and sales for up to 15 years, and, based on recorded values at December 31, 2001, approximately $139 million of net gains (net of income tax provision of $86 million) will be reclassified into earnings within the next year offsetting net losses that will be realized in earnings from unfavorable market movements associated with the underlying hedged transactions.

Energy commodity fair-value hedges

Williams' refineries carry inventories of crude oil and refined products. Williams enters into crude oil and refined products futures contracts and swap agreements to reduce the market exposure of these inventories from changing energy commodity prices. These derivatives have been designated as fair-value hedges. Derivative gains and losses from these fair-value hedges are recognized in earnings currently along with the change in fair value of the hedged item attributable to the risk being hedged. Gains and losses related to hedges of inventory are recognized in costs and operating expenses in the Consolidated Statement of Operations. Approximately $5 million of net gains from hedge ineffectiveness was recognized in costs and operating expenses in the Consolidated Statement of Operations during 2001. There were no derivative gains or losses excluded from the assessment of hedge effectiveness.

Other energy commodity derivatives

Williams' operations associated with crude oil refining and refined products marketing also include derivative transactions (primarily forward contracts, futures contracts, swap agreements and option contracts) which are not designated as hedges. The forward contracts are for the procurement of crude oil and refined products supply for operational purposes, while the other derivatives manage certain risks associated with market fluctuations in crude oil and refined product prices related to refined products marketing. The net change in fair value of these derivatives representing unrealized gains and losses is recognized in earnings currently as revenues or costs and operating expenses in the Consolidated Statement of Operations.

Foreign currency hedges

Williams has a Canadian-dollar-denominated note receivable that is exposed to foreign-currency risk. To protect against variability in the cash flows from the repayment of the note receivable associated with changes in foreign currency exchange rates, Williams entered into a forward contract to fix the U.S. dollar principal cash flows from this note. This derivative has been designated as a cash flow hedge and is expected to be highly effective over the period of the hedge. Gains and losses from the change in fair value of the derivative are deferred in other comprehensive income (loss) and reclassified to other income (expense) -- net below operating income when the Canadian-dollar-denominated note receivable impacts earnings as it is translated into U.S. dollars. There were no derivative gains or losses recorded in the Consolidated Statement of Operations from hedge ineffectiveness or from amounts excluded from the assessment of hedge effectiveness, and no foreign currency hedges were discontinued during 2001 as a result of it becoming probable that the forecasted transaction will not occur. This foreign-currency risk exposure is being hedged over the next 48 months. Of the $3.7 million net loss (net of income tax benefits of $2.3 million) deferred in other comprehensive income (loss) at December 31, 2001, the amount that will be reclassified into earnings over the next year will vary based on the gain or loss recognized as the note receivable is translated into U.S. dollars following changes in foreign-exchange rates.

Interest-rate derivatives

Williams enters into interest-rate swap agreements to manage its exposure to interest rates and modify the interest characteristics of its long-term debt. These agreements are designated with specific debt obligations, and involve the exchange of amounts based on the difference between fixed and variable interest rates calculated by reference to an agreed-upon notional amount. Interest-rate swaps in place during 2001 effectively modified Williams' exposure to interest rates by converting a portion of Williams' fixed rate debt to a variable rate. These derivatives were designated as fair value hedges and were perfectly effective. As a result, there was no current impact to earnings due to hedge ineffectiveness or due to the exclusion of a component of a derivative from the assessment of effectiveness. The change in fair value of the derivatives and the adjustments to the carrying amount of the underlying hedged debt were recorded as equal and offsetting gains and losses in other income (expense) -- net below operating income in the Consolidated Statement of Operations. There are no interest-rate derivatives designated as fair value hedges at December 31, 2001.

Kern River Gas Transmission had interest-rate swap agreements to manage interest-rate risk that were not designated as hedges of long-term debt. Changes in fair value were recorded each period in other income (expense) -- net below operating income in the Consolidated Statement of Operations. These agreements were terminated during 2001. Offsetting amounts were recorded as an adjustment to a regulatory asset, which is expected to be recovered in future transportation rates.

CONCENTRATION OF CREDIT RISK

Williams' cash equivalents consist of high-quality securities placed with various major financial institutions with credit ratings at or above AA by Standard & Poor's or Aa by Moody's Investor's Service. Williams' investment policy limits its credit exposure to any one issuer/obligor.

The following table summarizes concentration of receivables, net of allowances, by product or service at December 31, 2001 and 2000:

	2001	2000
	(MILLIONS)	
Receivables by product or service:		
Sale or transportation of natural gas and related products	$ 396.8	$ 507.8
Power sales and related services	1,445.3	1,148.7
Sale or transportation of petroleum products	841.6	518.3
Retained interest in accounts receivable sold to SPEs	205.0	936.4
Other	245.2	246.1
Total	$3,133.9	$3,357.3

Natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the eastern, northwestern and midwestern United States. Petroleum products customers include wholesale, commercial, governmental, industrial and individual consumers and independent dealers located primarily in Alaska and the midsouth and southeastern United States. Power customers include the California Independent System Operator (ISO), the California Department of Water Resources, other power marketers and utilities located throughout the majority of the United States. Collection of the retained interest in accounts receivable sold to the SPEs is dependent on the collection of the receivables. The underlying receivables are primarily for the sale or transportation of natural gas and related products or services and the sale of petroleum products in the United States. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

As of December 31, 2001, $388 million of certain power receivables from the ISO and the California Power Exchange have not been paid. In addition, Williams and other energy traders and marketers have been ordered to continue selling power to the ISO and certain other utilities irrespective of their credit ratings. Williams believes that it has appropriately reflected the collection and credit risk associated with receivables and trading assets in the statement of position and results of operations at December 31, 2001.

NOTE 19. CONTINGENT LIABILITIES AND COMMITMENTS

RATE AND REGULATORY MATTERS AND RELATED LITIGATION

Williams' interstate pipeline subsidiaries have various regulatory proceedings pending. As a result of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $96 million for potential refund as of December 31, 2001.

On January 30, 1998, the FERC convened a public conference to consider, on an industry-wide basis, issues with respect to rates of return for interstate natural gas pipelines. In July 1998, the FERC issued orders announcing a modification of its methodology for calculating a pipeline's return on equity. Certain parties appealed the FERC's action because the modified formula results in somewhat higher rates of return compared to the rates of return calculated by the prior formula. These appeals have been denied and the FERC has continued to utilize the formula as modified in 1998.

As a result of FERC Order 636 decisions in prior years, each of the natural gas pipeline subsidiaries has undertaken the reformation or termination of its respective gas supply contracts. None of the pipelines has any significant pending supplier take-or-pay, ratable take or minimum take claims.

Williams Energy Marketing & Trading subsidiaries are engaged in power marketing in various geographic areas, including California. Prices charged for power by Williams and other traders and generators in California and other western states have been challenged in various proceedings including those before the FERC. In December 2000, the FERC issued an order which provided that, for the period between October 2, 2000 and December 31, 2002, it may order refunds from Williams and other similarly situated companies if the FERC finds that the wholesale markets in California are unable to produce competitive, just and reasonable prices or that market power or other individual seller conduct is exercised to produce an unjust and unreasonable rate. Beginning on March 9, 2001, the FERC issued a series of orders directing Williams and other similarly situated companies to provide refunds for any prices charged in excess of FERC established proxy prices in January, February, March, April and May 2001, or to provide justification for the prices charged during those months. According to these orders, Williams' total potential refund liability for January through May 2001 is approximately $30 million. Williams has filed justification for its prices with the FERC and calculated its refund liability under the methodology used by the FERC to compute refund amounts at approximately $11 million. On July 25, 2001, the FERC issued an order establishing a hearing to establish the facts necessary to determine refunds under the approved methodology. Refunds under this order will cover the period of October 2, 2000 through June 20, 2001. They will be paid as offsets against outstanding bills and are inclusive of any amounts previously noticed for refund for that period. The judge presiding over the refund proceedings is expected to issue his findings in August 2002. The FERC will subsequently issue a refund order based on these findings.

In the order issued June 19, 2001, the FERC implemented a revised price mitigation and market monitoring plan for wholesale power sales by all suppliers of electricity, including Williams, in spot markets for a region that includes California and ten other western states (the "Western Systems Coordinating Council," or "WSCC"). In general, the plan, which will be in effect from June 20, 2001 through September 30, 2002, establishes a market clearing price for spot sales in all hours of the day that is based on the bid of the highest-cost gas-fired California generating unit that is needed to serve the ISO's load. When generation operating reserves fall below seven percent in California (a "reserve deficiency period"), absent cost-based justification for a higher price, the maximum price that Williams may charge for wholesale spot sales in the WSCC is the market clearing price. When generation operating reserves rise to seven percent or above in California, absent cost-based justification for a higher price, Williams' maximum price will be limited to 85 percent of the highest hourly price that was in effect during the most recent reserve deficiency period. This methodology initially resulted in a maximum price of $92 per megawatt hour during non-emergency periods and $108 per megawatt hour during emergency periods, and these maximum prices remained unchanged throughout Summer and Fall 2001.

The California Public Utilities Commission (CPUC) filed a complaint with the FERC on February 25, 2002, seeking to void or, alternatively, reform a number of the long-term power purchase contracts entered into between the State of California and several suppliers in 2001, including Energy Marketing & Trading. The CPUC alleges that the contracts are tainted with the exercise of market power and significantly exceed "just and reasonable" prices. The Electricity Oversight Board made a similar filing on February 27, 2002.

On December 19, 2001, the FERC reaffirmed its June 19 and July 25 orders with certain clarifications and modifications. It also altered the price mitigation methodology for spot market transactions for the WSCC market for the winter 2001 season and set the period maximum price at $108 per megawatt hour through April 30, 2002. Under the order, this price would be subject to being recalculated when the average gas price rises by a minimum factor of ten percent effective for the following trading day, but in no event will the maximum price drop below $108 per megawatt hour. The FERC also upheld a ten percent addition to the price applicable to sales into California to reflect credit risk.

Certain entities have also asked the FERC to revoke Williams' authority to sell power from California-based generating units at market-based rates to limit Williams to cost-based rates for future sales from such units and to order refunds of excessive rates, with interest, back to May 1, 2000, and possibly earlier.

On March 14, 2001, the FERC issued a Show Cause Order directing Williams Energy Marketing & Trading Company and AES Southland, Inc. to show cause why they should not be found to have engaged in violations of the Federal Power Act and various agreements, and they were directed to make refunds in the aggregate of approximately $10.8 million, and have certain conditions placed on Williams' market-based rate authority for sales from specific generating facilities in California for a limited period. On April 30, 2001, the FERC issued an Order approving a settlement of this proceeding. The settlement terminated the proceeding without making any findings of wrongdoing by Williams. Pursuant to the settlement, Williams agreed to refund $8 million to the ISO by crediting such amount against outstanding invoices. Williams also agreed to prospective conditions on its authority to make bulk power sales at market-based rates for certain limited facilities under which it has call rights for a one-year period. Williams also has been informed that the facts underlying this proceeding are also under investigation by a California Grand Jury.

On September 27, 2001, the FERC issued a Notice of Proposed Rulemaking proposing to adopt uniform standards of conduct for transmission providers. The proposed rules define transmission providers as interstate natural gas pipelines and public utilities that own, operate or control electric transmission facilities. The proposed standards would regulate the conduct of transmission providers with their energy affiliates. The FERC proposes to define energy affiliates broadly to include any transmission provider affiliate that engages in or is involved in transmission (gas or electric) transactions, or manages or controls transmission capacity, or buys, sells, trades or administers natural gas or electric energy or engages in financial transactions relating to the sale or transmission of natural gas or electricity. Current rules affecting Williams regulate the conduct of Williams' natural gas pipelines and their natural gas marketing affiliates. If adopted, these new standards would require the adoption of new compliance measures by certain Williams subsidiaries.

On February 13, 2002, the FERC issued an Order Directing Staff Investigation commencing a proceeding titled Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices. Through the investigation, the FERC intends to determine whether "any entity, including Enron Corporation (through any of its affiliates or subsidiaries), manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over wholesale electric prices in the West, since January 1, 2000, resulting in potentially unjust and unreasonable rates in long-term power sales contracts subsequently entered into by sellers in the West." This investigation does not constitute a Federal Power Act complaint, rather, the results of the investigation will be used by the FERC in any existing or subsequent Federal Power

Act or Natural Gas Act complaint. The FERC Staff is directed to complete the investigation as soon as "is practicable." Williams, through many of its subsidiaries, is a major supplier of natural gas and power in the West and, as such, anticipates being the subject of certain aspects of the investigation.

ENVIRONMENTAL MATTERS

Since 1989, Texas Gas and Transcontinental Gas Pipe Line have had studies under way to test certain of their facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transcontinental Gas Pipe Line has responded to data requests regarding such potential contamination of certain of its sites. The costs of any such remediation will depend upon the scope of the remediation. At December 31, 2001, these subsidiaries had accrued liabilities totaling approximately $33 million for these costs.

Certain Williams subsidiaries, including Texas Gas and Transcontinental Gas Pipe Line, have been identified as potentially responsible parties (PRP) at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws. Although no assurances can be given, Williams does not believe that these obligations or the PRP status of these subsidiaries will have a material adverse effect on its financial position, results of operations or net cash flows.

Transcontinental Gas Pipe Line, Texas Gas and Williams Gas Pipelines Central (Central) have identified polychlorinated biphenyl contamination in air compressor systems, soils and related properties at certain compressor station sites. Transcontinental Gas Pipe Line, Texas Gas and Central have also been involved in negotiations with the U.S. Environmental Protection Agency (EPA) and state agencies to develop screening, sampling and cleanup programs. In addition, negotiations with certain environmental authorities and other programs concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites have been commenced by Central, Texas Gas and Transcontinental Gas Pipe Line. As of December 31, 2001, Central had accrued a liability for approximately $9 million, representing the current estimate of future environmental cleanup costs to be incurred over the next six to ten years. Texas Gas and Transcontinental Gas Pipe Line likewise had accrued liabilities for these costs which are included in the $33 million liability mentioned above. Actual costs incurred will depend on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

In July 1999, Transcontinental Gas Pipe Line received a letter stating that the U.S. Department of Justice (DOJ), at the request of the EPA, intends to file a civil action against Transcontinental Gas Pipe Line arising from its waste management practices at Transcontinental Gas Pipe Line's compressor stations and metering stations in 11 states from Texas to New Jersey. Transcontinental Gas Pipe Line, the EPA and the DOJ agreed to settle this matter by signing a Consent Decree that provides for a civil penalty of $1.4 million.

Williams Energy Services (WES) and its subsidiaries also accrue environmental remediation costs for its natural gas gathering and processing facilities, petroleum products pipelines, retail petroleum and refining operations and for certain facilities related to former propane marketing operations primarily related to soil and groundwater contamination. In addition, WES owns a discontinued petroleum refining facility that is being evaluated for potential remediation efforts. At December 31, 2001, WES and its subsidiaries had accrued liabilities totaling approximately $43 million. WES accrues receivables related to environmental remediation costs based upon an estimate of amounts that will be reimbursed from state funds for certain expenses associated with underground storage tank problems and repairs. At December 31, 2001, WES and its subsidiaries had accrued receivables totaling $1 million.

Williams Field Services (WFS), a WES subsidiary, received a Notice of Violation (NOV) from the EPA in February 2000. WFS received a contemporaneous letter from the DOJ indicating that the DOJ will also be involved in the matter. The NOV alleged violations of the Clean Air Act at a gas processing plant. WFS, the EPA and the DOJ agreed to settle this matter for a penalty of $850,000. In the course of investigating this matter, WFS discovered a similar potential violation at the plant and disclosed it to the EPA and the DOJ. In December 2001, the EPA, the DOJ and WFS agreed to settle this self-reported matter by signing a Consent Decree that provides for a penalty of $950,000.

In connection with the 1987 sale of the assets of Agrico Chemical Company, Williams agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations, to the extent such costs exceed a specified amount. At December 31, 2001, Williams had approximately $10 million accrued for such excess costs. The actual costs incurred will depend on the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA or other governmental authorities, and other factors.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from Williams' pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period July 1, 1998 through July 2, 2001. In November 2001, Williams furnished its response.

OTHER LEGAL MATTERS

In connection with agreements to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transcontinental Gas Pipe Line and Texas Gas each entered into certain settlements with producers which may require the indemnification of certain claims for additional royalties which the producers may be required to pay as a result of such settlements. As a result of such settlements, Transcontinental Gas Pipe Line is currently defending three lawsuits brought by producers. In one of the cases, a jury verdict found that Transcontinental Gas Pipe Line was required to pay a producer damages of $23.3 million including $3.8 million in attorneys' fees. In addition, through December 31, 2001, post-judgment interest was approximately $10.5 million. Transcontinental Gas Pipe Line's appeals have been denied by the Texas Court of Appeals for the First District of Texas, and on April 2, 2001, the company filed an appeal to the Texas Supreme Court. On February 21, 2002, the Texas Supreme Court denied Transcontinental Gas Pipe Line's petition for review. As a result, Transcontinental Gas Pipe Line recorded a pre-tax charge to income (loss) for the year ended December 31, 2001 in the amount of $37 million ($18 million is included in Gas Pipeline's segment profit and $19 million in interest accrued) representing management's estimate of the effect of this ruling. Transcontinental Gas Pipe Line plans to request rehearing of the court's decision. In the other cases, producers have asserted damages, including interest calculated through December 31, 2001, of $16.3 million. Producers have received and may receive other demands, which could result in additional claims. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the settlement between the producer and either Transcontinental Gas Pipe Line or Texas Gas. Texas Gas may file to recover 75 percent of any such additional amounts it may be required to pay pursuant to indemnities for royalties under the provisions of Order 528.

On June 8, 2001, 14 Williams entities were named as defendants in a nationwide class action lawsuit which has been pending against other defendants, generally pipeline and gathering companies, for more than one year. The plaintiffs allege that the defendants, including the Williams defendants, have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs. In September 2001, the plaintiffs voluntarily dismissed two of the 14 Williams entities named as defendants in the lawsuit. In November 2001, Williams, along with other Coordinating Defendants, filed a motion to dismiss under Rules 9b and 12b of the Kansas Rules of Civil Procedure. In January 2002, most of the Williams defendants, along with a group of Coordinating Defendants, filed a motion to dismiss for lack of personal jurisdiction. The court has not yet ruled on these motions. In the next several months, the Williams entities will join with other defendants in contesting certification of the plaintiff class.

In 1998, the United States Department of Justice informed Williams that Jack Grynberg, an individual, had filed claims in the United States District Court for the District of Colorado under the False Claims Act against Williams and certain of its wholly owned subsidiaries including Central, Kern River Gas Transmission, Northwest Pipeline, Williams Gas Pipeline Company, Transcontinental Gas Pipe Line Corporation, Texas Gas, Williams Field Services Company and Williams Production Company. Mr. Grynberg has also filed claims against approximately 300 other energy companies and alleges that the defendants violated the False Claims Act in connection with the measurement and purchase of hydrocarbons. The relief sought is an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys' fees, and costs. On April 9, 1999, the United States Department of Justice announced that it was declining to intervene in any of the Grynberg qui tam cases, including the action filed against the Williams entities in the United States District Court for the District of Colorado. On October 21, 1999, the Panel on Multi-District Litigation transferred all of the Grynberg qui tam cases, including those filed against Williams, to the United States District Court for the District of Wyoming for pre-trial purposes. Motions to dismiss the complaints filed by various defendants, including Williams, were denied on May 18, 2001.

Williams and certain of its subsidiaries are named as defendants in various putative, nationwide class actions brought on behalf of all landowners on whose property the plaintiffs have alleged WCG installed fiber-optic cable without the permission of the landowners. Williams believes that WCG's installation of the cable containing the fiber network that crosses over or near the putative class members' land does not infringe on their property rights. Williams also does not believe that the plaintiffs have sufficient basis for certification of a class action. It is likely that Williams will be subject to other putative class action suits challenging WCG's railroad or pipeline rights of way. However, Williams has a claim for indemnity from WCG, subject to their ability to perform, for damages resulting from or arising out of the businesses or operations conducted or formerly conducted or assets owned or formerly owned by any subsidiary of WCG.

In November 2000, class actions were filed in San Diego, California Superior Court by Pamela Gordon and Ruth Hendricks on behalf of San Diego rate payers against California power generators and traders including Williams Energy Services Company and Williams Energy Marketing & Trading Company, subsidiaries of Williams. Three municipal water districts also filed a similar action on their own behalf. Other class actions have been filed on behalf of the people of California and on behalf of commercial restaurants in San Francisco Superior Court. These lawsuits result from the increase in wholesale power prices in California that began in the summer of 2000. Williams is also a defendant in other litigation arising out of California energy issues. The suits claim that the defendants acted to manipulate prices in violation of the California antitrust and unfair business practices statutes and other state and federal laws. Plaintiffs are seeking injunctive relief as well as restitution, disgorgement, appointment of a receiver, and damages, including treble damages. These cases have all been coordinated in San Diego County Superior Court.

On May 2, 2001, the Lieutenant Governor of the State of California and Assemblywoman Barbara Matthews, acting in their individual capacities as members of the general public, filed suit against five companies including Williams Energy Marketing & Trading and 14 executive officers, including Keith Bailey, Chairman of Williams, Steve Malcolm, President and CEO of Williams, and Bill Hobbs, President and CEO of Williams Energy Marketing & Trading, in Los Angeles Superior State Court alleging State Antitrust and Fraudulent and Unfair Business Act Violations and seeking injunctive and declaratory relief, civil fines, treble damages and other relief, all in an unspecified amount. This case is being coordinated with the other class actions in San Diego Superior Court.

On May 17, 2001, the DOJ advised Williams that it had commenced an antitrust investigation relating to an agreement between a subsidiary of Williams and AES Southland alleging that the agreement limits the expansion of electric generating capacity at or near the AES Southland plants that are subject to a long-term tolling agreement between Williams and AES Southland. In connection with that investigation, the DOJ has issued two Civil Investigative Demands to Williams requesting answers to certain interrogatories and the production of documents. Williams is cooperating with the investigation.

On October 5, 2001, suit was filed on behalf of California taxpayers and electric ratepayers in the Superior Court for the County of San Francisco against the Governor of California and 22 other defendants consisting of other state officials, utilities and generators, including Energy Marketing & Trading. The suit alleges that the long-term power contracts entered into by the state with generators are illegal and unenforceable on the basis of fraud, mistake, breach of duty, conflict of interest, failure to comply with law, commercial impossibility and change in circumstances. Remedies sought include rescission, reformation, injunction, and recovery of funds.

On October 19, 2001, Williams settled a $42 million claim for coal royalty payments relating to a discontinued activity by agreeing to pay $9.5 million.

Since January 29, 2002, Williams is aware of numerous shareholder class action suits that have been filed in the United States District Court for the Northern District of Oklahoma. The majority of the suits allege that Williams and co-defendants, Williams Communications and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002, known as the FELINE PACS offering. This case was filed against Williams, certain corporate officers, all members of the Williams board of directors and all of the offerings' underwriters. Williams does not anticipate any immediate action by the Court in these actions. In addition, class action complaints have been filed against Williams and the members of its board of directors under the Employee Retirement Income Security Act by participants in Williams' 401(k) plan based on similar allegations.

In addition to the foregoing, various other proceedings are pending against Williams or its subsidiaries which are incidental to their operations.

Enron Corp. (Enron) and certain of its subsidiaries, with whom Energy Marketing & Trading and other Williams subsidiaries have had commercial relations, filed a voluntary petition for Chapter 11 reorganization under the U.S. Bankruptcy Code in the Federal District Court for the Southern District of New York on December 2, 2001. Additional Enron subsidiaries have subsequently filed for Chapter 11. The court has not set a date for the filing of claims. During fourth-quarter 2001, Energy Marketing & Trading recorded a total decrease to revenues of approximately $130 million as a part of its valuation of energy commodity and derivative trading contracts with Enron entities, approximately $91 million of which was recorded pursuant to events immediately preceding and following the announced bankruptcy of Enron. Other Williams subsidiaries recorded approximately $5 million of bad debt expense related to amounts receivable from Enron entities in fourth-quarter 2001, reflected in selling, general and administrative expenses. At December 31, 2001, Williams has reduced its recorded exposure to accounts receivable from Enron entities, net of margin deposits, to expected recoverable amounts.

SUMMARY

While no assurances may be given, Williams, based on advice of counsel, does not believe that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will have a materially adverse effect upon Williams' future financial position, results of operations or cash flow requirements.

COMMITMENTS

Energy Marketing & Trading has entered into certain contracts giving Williams the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are either currently in operation or are to be constructed at various locations throughout the continental United States. At December 31, 2001, annual estimated committed payments under these contracts range from approximately $20 million to $462 million, resulting in total committed payments over the next 21 years of approximately $8 billion.

See Note 4 for commitments related to certain equity and cost method investments and Note 11 for commitments for construction and acquisition of property, plant and equipment.

NOTE 20. RELATED PARTY TRANSACTIONS

In fourth-quarter 2000, Williams entered into a $600 million debt obligation with Lehman Brothers Inc. Lehman Brothers Inc. is a related party as a result of a director that serves on both Williams' and Lehman Brothers Holdings, Inc.'s board of directors. This debt obligation was paid in first-quarter 2001. In addition, Williams paid $27 million to Lehman Brothers Inc. in 2001, primarily for underwriting fees related to debt and equity issuances.

NOTE 21. ACCUMULATED OTHER COMPREHENSIVE INCOME

The table below presents changes in the components of accumulated other comprehensive income.

	INCOME (LOSS)				
	CASH FLOW HEDGES	UNREALIZED APPRECIATION (DEPRECIATION) ON SECURITIES	FOREIGN CURRENCY TRANSLATION	MINIMUM PENSION LIABILITY	TOTAL
	(MILLIONS)				
Balance at December 31, 1998...	$ --	$ 21.7	$ (5.0)	$ --	$ 16.7
1999 change:					
Pre-income tax amount........	--	194.9	(17.9)	--	177.0
Income tax provision.........	--	(75.8)	--	--	(75.8)
Minority interest in other comprehensive income......	--	(14.9)	(.1)	--	(15.0)
	--	104.2	(18.0)	--	86.2
Adjustment due to issuance of subsidiary's common stock....	--	(5.8)	2.4	--	(3.4)
Balance at December 31, 1999...	--	120.1	(20.6)	--	99.5
2000 change:					
Pre-income tax amount........	--	218.1	(28.2)	--	189.9
Income tax provision.........	--	(82.2)	--	--	(82.2)
Minority interest in other comprehensive income (loss)....................	--	(20.4)	4.3	--	(16.1)
Net realized gains in net income (net of $118.3 income tax benefit and $28.0 minority interest)................	--	(162.9)	--	--	(162.9)
	--	(47.4)	(23.9)	--	(71.3)
Balance at December 31, 2000...	--	72.7	(44.5)	--	28.2
2001 change:					
Cumulative effect of change in accounting for derivative instruments (net of a $58.9 million income tax benefit).......	(94.5)	--	--	--	(94.5)
Pre-income tax amount........	896.8	(69.7)	(39.9)	(3.6)	783.6
Income tax benefit (provision)..............	(343.3)	27.5	--	1.4	(314.4)
Minority interest in other comprehensive loss........	--	5.4	2.8	--	8.2
Net realized gains in net income (net of $.1 income tax benefit and $1.8 minority interest)........	--	1.5	--	--	1.5
Net reclassification into earnings of derivative instrument gains (net of a $55.7 million income tax benefit).................	(88.8)	--	--	--	(88.8)
	370.2	(35.3)	(37.1)	(2.2)	295.6
Adjustment due to spinoff of WCG..........................	--	(36.5)	57.8	--	21.3
Balance at December 31, 2001...	$ 370.2	$ .9	$(23.8)	$(2.2)	$ 345.1

Unrealized appreciation (depreciation) on securities for years prior to 2000 represents activity related to securities held by WCG. At December 31, 2000, the unrealized appreciation (depreciation) on securities balance includes $76.1 million of unrealized net appreciation related to securities held by WCG. Foreign currency translation balances include translation losses of $38.5 million and $13.6 million at December 31, 2000 and 1999, respectively, which relate to WCG. The adjustment due to the spinoff of WCG for 2001 includes unrealized appreciation (depreciation) on securities and foreign currency translation balances which relate to WCG and are included in the $2.0 billion decrease to stockholders' equity (see Note 3). The remaining balances relate to the continuing operations of Williams.

NOTE 22. SEGMENT DISCLOSURES

Williams evaluates performance based upon segment profit (loss) from operations which includes revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments. The accounting policies of the segments are the same as those described in Note 1, Summary of Significant Accounting Policies. Intersegment sales are generally accounted for as if the sales were to unaffiliated third parties, that is, at current market prices.

The majority of energy commodity hedging by the Energy Services' business units is done through intercompany derivatives with Energy Marketing & Trading which, in turn, enters into offsetting derivative contracts with unrelated third parties. Energy Marketing & Trading bears the counter party performance risks associated with unrelated third parties. Similarly, hedging of interest rate risk in the energy trading portfolio by Energy Marketing & Trading is facilitated by the corporate treasury operation. All hedging effectiveness, ineffectiveness and risk of this activity is recognized by Energy Marketing & Trading.

Williams' reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. Other includes corporate operations.

Segment amounts for 2000 and 1999 have been restated to reflect two new reporting segments, International and Williams Energy Partners, and the reclassification of Energy Marketing & Trading to a third industry group (see Note 1).

Exploration & Production's 2001 additions to long-lived assets and increase in total assets, as noted on pages 132 and 133, respectively, are due primarily to the Barrett acquisition (see Note 2).

The following table reflects the reconciliation of operating income as reported on the Consolidated Statement of Operations to segment profit (loss), per the table on page 132.

	OPERATING INCOME	EQUITY EARNINGS (LOSSES)	INCOME (LOSS) FROM INVESTMENTS	SEGMENT PROFIT
		(MILLIONS)		
2001				
Energy Marketing & Trading	$1,296.1	$ (1.3)	$(23.3)	$1,271.5
Gas Pipeline	673.8	46.3	--	720.1
Energy Services	591.5	(21.6)	--	569.9
Other	12.9	(.7)	--	12.2
Total segments	2,574.3	$ 22.7	$(23.3)	$2,573.7
General corporate expenses	(124.3)			
Total operating income	$2,450.0			
2000				
Energy Marketing & Trading	$1,005.5	$ 1.6	$ .8	$1,007.9
Gas Pipeline	714.5	27.0	--	741.5
Energy Services	571.7	(6.8)	--	564.9
Other	11.5	(.2)	--	11.3
Total segments	2,303.2	$ 21.6	$ .8	$2,325.6
General corporate expenses	(97.2)			
Total operating income	$2,206.0			
1999				
Energy Marketing & Trading	$ 104.5	$ (.5)	$ --	$ 104.0
Gas Pipeline	688.3	9.0	--	697.3
Energy Services	439.6	(18.4)	--	421.2
Other	11.1	3.6	--	14.7
Total segments	1,243.5	$ (6.3)	$ --	$1,237.2
General corporate expenses	(76.9)			
Total operating income	$1,166.6			

The following geographic area data includes revenues from external customers based on product shipment origin and long-lived assets based upon physical location.

	2001	2000	1999
		(MILLIONS)	
Revenues from external customers:			
United States	$ 9,625.7	$ 9,283.7	$ 6,522.3
Other	1,409.0	308.2	107.1
Total	$11,034.7	$ 9,591.9	$ 6,629.4
Long-lived assets:			
United States	$17,543.3	$13,121.8	$12,522.4
Other	1,356.5	1,126.6	354.4
Total	$18,899.8	$14,248.4	$12,876.8

Long-lived assets are comprised of property, plant and equipment and goodwill and other intangible assets.

	REVENUES						
	EXTERNAL CUSTOMERS	INTERSEGMENT	TOTAL	SEGMENT PROFIT (LOSS)	EQUITY EARNINGS (LOSSES)	ADDITIONS TO LONG-LIVED ASSETS	DEPRECIATION, DEPLETION & AMORTIZATION
				(MILLIONS)			
2001							
Energy Marketing & Trading.....	$2,573.5	$ (701.7)*	$ 1,871.8	$1,271.5	$ (1.3)	$ 209.6	$ 21.1
Gas Pipeline...................	1,698.3	50.5	1,748.8	720.1	46.3	872.2	330.5
Energy Services							
Exploration & Production.....	86.0	493.6	579.6	218.7	8.5	3,770.2	94.6
International................	159.0	--	159.0	(172.8)	(13.1)	123.3	38.4
Midstream Gas & Liquids......	1,327.3	595.1	1,922.4	221.6	(16.9)	489.5	179.8
Petroleum Services...........	5,083.5	324.4	5,407.9	286.9	(.1)	115.6	105.3
Williams Energy Partners.....	70.3	15.9	86.2	17.0	--	66.0	12.3
Merger-related costs.........	--	--	--	(1.5)	--	--	--
Total Energy Services............	6,726.1	1,429.0	8,155.1	569.9	(21.6)	4,564.6	430.4
Other..........................	36.8	39.5	76.3	12.2	(.7)	34.9	15.7
Eliminations...................	--	(817.3)	(817.3)	--	--	--	--
Total.................	$11,034.7	$ --	$11,034.7	$2,573.7	$ 22.7	$5,681.3	$797.7
2000							
Energy Marketing & Trading.....	$2,273.2	$ (700.6)*	$ 1,572.6	$1,007.9	$ 1.6	$ 68.8	$ 18.7
Gas Pipeline...................	1,818.6	60.6	1,879.2	741.5	27.0	664.4	294.1
Energy Services							
Exploration & Production.....	39.6	254.6	294.2	62.4	--	70.7	29.1
International................	104.1	--	104.1	14.1	(2.2)	327.1	18.1
Midstream Gas & Liquids......	835.1	679.6	1,514.7	297.9	(4.0)	799.2	163.0
Petroleum Services...........	4,436.5	168.5	4,605.0	175.8	(.6)	189.8	95.5
Williams Energy Partners.....	56.1	17.4	73.5	21.8	--	42.0	9.1
Merger-related costs.........	--	--	--	(7.1)	--	--	--
Total Energy Services............	5,471.4	1,120.1	6,591.5	564.9	(6.8)	1,428.8	314.8
Other..........................	28.7	38.1	66.8	11.3	(.2)	43.2	19.2
Eliminations...................	--	(518.2)	(518.2)	--	--	--	--
Total.................	$9,591.9	$ --	$ 9,591.9	$2,325.6	$ 21.6	$2,205.2	$646.8
1999							
Energy Marketing & Trading.....	$1,217.7	$ (555.4)*	$ 662.3	$ 104.0	$ (.5)	$ 82.8	$ 35.3
Gas Pipeline...................	1,762.7	59.9	1,822.6	697.3	9.0	361.3	285.1
Energy Services							
Exploration & Production.....	50.2	139.9	190.1	39.8	--	148.5	23.5
International................	72.5	--	72.5	(3.9)	(6.8)	247.9	11.9
Midstream Gas & Liquids......	648.9	381.5	1,030.4	223.9	(12.1)	341.5	143.2
Petroleum Services...........	2,812.6	175.2	2,987.8	157.8	.5	488.5	78.9
Williams Energy Partners.....	36.7	6.9	43.6	16.3	--	227.6	4.6
Merger-related costs.........	--	--	--	(12.7)	--	--	--
Total Energy Services............	3,620.9	703.5	4,324.4	421.2	(18.4)	1,454.0	262.1
Other..........................	28.1	37.3	65.4	14.7	3.6	42.7	23.0
Eliminations...................	--	(245.3)	(245.3)	--	--	--	--
Total.................	$6,629.4	$ --	$ 6,629.4	$1,237.2	$ (6.3)	$1,940.8	$605.5

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* Energy Marketing & Trading intercompany cost of sales, which are netted in revenues consistent with fair-value accounting, exceed intercompany revenues.

	TOTAL ASSETS		EQUITY METHOD INVESTMENTS	
	DECEMBER 31, 2001	DECEMBER 31, 2000	DECEMBER 31, 2001	DECEMBER 31, 2000
	(MILLIONS)			
Energy Marketing & Trading	$15,483.0	$14,609.7	$ --	$ 1.4
Gas Pipeline	9,253.0	8,817.2	715.5	281.5
Energy Services				
Exploration & Production	4,925.7	671.5	--	--
International	2,101.1	2,214.4	127.8	119.3
Midstream Gas & Liquids	4,484.4	4,293.5	217.8	239.2
Petroleum Services	2,907.7	2,666.5	110.1	113.2
Williams Energy Partners	401.3	349.8	--	--
Total Energy Services	14,820.2	10,195.7	455.7	471.7
Other	7,344.5	7,019.9	--	--
Eliminations	(7,994.5)	(8,156.1)	--	--
	38,906.2	32,486.4	1,171.2	754.6
Net assets of discontinued operations	--	2,290.2	--	--
Total assets	$38,906.2	$34,776.6	$1,171.2	$754.6

NOTE 23. SUBSEQUENT EVENTS

In January 2002, Williams issued 44 million publicly traded units, more commonly known as FELINE PACs, that include a senior debt security and an equity purchase contract. The debt has a term of five years, and the equity purchase contract will require the company to deliver Williams common stock to holders after three years based on a previously agreed rate. Net proceeds from this issuance were approximately $1.1 billion.

The FELINE PACS were issued as part of Williams' plan to strengthen its balance sheet and maintain its investment-grade rating. Some of the steps which could impact amounts recorded at December 31, 2001 include:

- A $1 billion reduction in planned capital spending for 2002.

- Sales of certain non-core assets during 2002, from which Williams expects to receive proceeds of between $250 million and $750 million.

- Initiation of action to eliminate ratings triggers on certain obligations and contingencies that do not appear as debt on the Consolidated Balance Sheet.

Williams has also announced plans to sell its midwest petroleum products pipeline and on-system terminals. A potential buyer would be Williams Energy Partners, L.P., a consolidated entity.

THE WILLIAMS COMPANIES, INC.

QUARTERLY FINANCIAL DATA
(UNAUDITED)

Summarized quarterly financial data are as follows (millions, except per-share amounts). Certain amounts have been restated or reclassified as described in Note 1 of Notes to Consolidated Financial Statements.

2001	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
Revenues	$3,096.2	$2,815.0	$2,804.6	$2,318.9
Costs and operating expenses	2,045.5	1,984.1	1,809.9	1,545.1
Income (loss) from continuing operations	378.3	339.5	221.3	(103.7)
Net income (loss)	199.2	339.5	221.3	(1,237.7)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	.79	.70	.44	(.20)
Net income (loss)	.42	.70	.44	(2.39)
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	.78	.69	.44	(.20)
Net income (loss)	.41	.69	.44	(2.39)

2000	FIRST QUARTER	SECOND QUARTER	THIRD QUARTER	FOURTH QUARTER
Revenues	$1,898.9	$2,351.5	$2,330.9	$3,010.6
Costs and operating expenses	1,314.9	1,494.5	1,671.6	1,960.8
Income from continuing operations	138.9	286.4	176.5	363.6
Net income (loss)	99.7	351.8	121.1	(48.3)
Basic earnings (loss) per common share:				
Income from continuing operations	.31	.64	.39	.81
Net income (loss)	.22	.79	.27	(.11)
Diluted earnings (loss) per common share:				
Income from continuing operations	.31	.63	.39	.80
Net income (loss)	.22	.78	.27	(.11)

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to changes in the average number of common shares outstanding and rounding.

First-quarter 2001 net income includes an after-tax loss from discontinued operations of $179.1 million related to the spinoff of WCG and fourth-quarter 2001 loss from discontinued operations includes $1.17 billion after-tax impact for accruals of WCG guarantees and payment obligations (see Note 3). Additionally, first and fourth-quarter 2001 net income (loss) includes additional pre-tax impairment charges of $11.2 million and $.9 million, respectively, relating to Petroleum Services' end-to-end mobile computing systems business.

Second and fourth-quarter 2001 net income (loss) includes a pre-tax gain from the sale of certain convenience stores at Petroleum Services of $72.1 million and $3.2 million, respectively. Second and third-quarter 2001 net income includes a pre-tax impairment loss related to certain south Texas non-regulated gathering and processing assets at Midstream Gas & Liquids of $10.9 million and $4.2 million, respectively. A $1.3 million reduction to these impairment charges was made in fourth-quarter 2001 based on proceeds from the sales which closed in first-quarter 2002. Additionally, second-quarter 2001 includes a $27.5 million pre-tax gain on the sale of Williams' limited partnership interest in Northern Border Partners, L.P. at Gas Pipeline.

Included in third-quarter 2001 net income is a $94.2 million pre-tax charge related to the write-down of certain equity and cost basis investments (see Note 4).

Fourth-quarter 2001 net income (loss) includes a $170 million pre-tax impairment charge relating to the soda ash mining operations located in Colorado (see Note 5). Also, included in fourth-quarter 2001 net income (loss) is a $130 million pre-tax decrease to revenues and a $5 million pre-tax charge to bad expense related to Williams' estimated net exposure for the Enron bankruptcy at Energy Marketing & Trading and Gas Pipeline, respectively (see Note 19), a $13.3 million pre-tax impairment charge for the termination of a plant expansion at Energy Marketing & Trading and a $14.7 million pre-tax impairment charge and other loss accruals related to certain travel centers at Petroleum Services. Additionally, fourth-quarter 2001 net income (loss) includes a $37 million pre-tax charge resulting from an unfavorable court decision in one of Transcontinental Gas Pipe Line's royalty claims proceeding (see Note 19) and $213 million pre-tax charges included in continuing operations related to estimated losses from an assessment of the recoverability of WCG related receivables (see Note 3).

Second-quarter 2000 net income includes approximately $75 million in pre-tax reductions to certain rate refund liabilities and related interest accruals based on favorable FERC and judicial rulings received regarding regulatory proceedings. Also included in second and fourth-quarter 2000 net income (loss) is a $25.9 million and a $17.2 million pre-tax charge, respectively, resulting from the decision to discontinue Energy Marketing & Trading's mezzanine lending services (see Note 5). Fourth-quarter 2000 net income includes a $16.3 million pre-tax charge relating to management's decision and commitment to sell Energy Marketing & Trading's distributed power generation business and an $11.9 million pre-tax charge relating to management's decision and commitment to sell certain of Petroleum Services' end-to-end mobile computing systems business. These charges represent the impairment of the assets to fair value based on the expected net sales proceeds.

First, third and fourth-quarter 2000 include after-tax loss from discontinued operations of $39.2 million, $55.4 million and $411.9 million, respectively, while second-quarter 2000 includes after-tax income of $65.4 million, all of which are related to WCG which was spun off April 23, 2001 (see Note 3).

SUPPLEMENTAL OIL AND GAS DISCLOSURES
(UNAUDITED)

The following information pertains to the Company's oil and gas producing activities and is presented in accordance with SFAS No. 69 "Disclosures About Oil and Gas Producing Activities". The information is required to be disclosed by geographic region. Williams has significant oil and gas producing activities primarily in the Rocky Mountain, Mid-continent and Gulf Coast regions of the United States. Additionally, Williams has oil and gas producing activities in Argentina; however, proved reserves and revenues related to these activities are approximately 5.6 percent and 4.3 percent, respectively, of Williams' total oil and gas producing activities. The following information relates only to the oil and gas activities in the United States.

CAPITALIZED COSTS

	FOR THE YEAR ENDED DECEMBER 31, 2001
	(MILLIONS)
Proved properties	$2,415.2
Unproved properties	851.9
	3,267.1
Accumulated depreciation, depletion, and amortization, and valuation provisions	268.3
Net capitalized costs	$2,998.8

- Capitalized costs include the cost of equipment and facilities for oil and gas producing activities. This amount does not include approximately $1 billion of goodwill related to the purchase of Barrett Resources Corp. (Barrett).

- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); successful exploratory wells and related equipment and facilities (and uncompleted exploratory well costs) and support equipment.

- Unproved properties consist primarily of acreage related to probable reserves acquired through the Barrett acquisition in addition to a small portion of unproved exploratory acreage.

COSTS INCURRED DURING 2001

	FOR THE YEAR ENDED DECEMBER 31, 2001
	(MILLIONS)
Acquisition	$2,557.0
Exploration	35.6
Development	198.9
	$2,791.5

- Costs incurred include capitalized and expensed items.

- Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire property, the majority of which is related to the Barrett acquisition. This amount does not include approximately $1 billion of goodwill related to the purchase of Barrett.

- Exploration costs include the costs of geological and geophysical activity, dry holes, drilling and equipping exploratory wells, and the cost of retaining undeveloped leaseholds.

- Development costs include costs incurred to gain access to and prepare development well locations for drilling and to drill and equip development wells.

RESULTS OF OPERATIONS

	FOR THE YEAR ENDED DECEMBER 31, 2001
	(MILLIONS)
Revenues:	
Oil and gas revenues	$408.4
Other revenues	171.2
Total revenues	579.6
Costs:	
Production costs	79.3
General & administrative	40.1
Exploration expenses	10.1
Depreciation, depletion & amortization	94.0
Property impairments	7.2
Other expenses	138.7
Total expenses	369.4
Results of operations	210.2
Equity earnings	8.5
Provision for income taxes	(80.4)
Exploration and production net income	$138.3

- Results of operations for producing activities consist of all related activities within the Exploration & Production reporting unit.

- Oil and gas revenues consist primarily of natural gas production sold to Energy Marketing & Trading and includes the impact of intercompany hedges.

- Other revenues and other expenses consist of activities within the Exploration & Production segment that are not a direct part of the producing activities. These non-producing activities include acquisition and disposition of other working interest and royalty interest gas and the movement of gas from the wellhead to the tailgate of the respective plants for sale to Energy Marketing & Trading or third party purchases. In addition, other revenues include recognition of income from transactions which transferred certain non-operating benefits to a third party.

- Production costs consist of costs incurred to operate and maintain wells and related equipment and facilities used in the production of petroleum liquids and natural gas. These costs also include production related taxes other than income taxes, and administrative expenses related to the production activity. Excluded are depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

- Exploration expenses include unsuccessful exploratory dry hole costs, leasehold impairment, geological and geophysical expenses and the cost of retaining undeveloped leaseholds.

- Depreciation, depletion and amortization includes depreciation of support equipment.

PROVED RESERVES

	2001
	(BCFE)
Proved reserves at beginning of period	1,202
Revisions	(69)
Purchases	1,949
Extensions and discoveries	239
Production	(131)
Sale of minerals in place	(12)
Proved reserves at end of period	3,178
Proved developed reserves at end of period	1,599

- Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit. Crude oil reserves are insignificant and have been included in the proved reserves on a basis of billion cubic feet equivalents (Bcfe).

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following is based on the estimated quantities of proved reserves and the year-end prices and costs. The average year end natural gas prices used in the following estimates were $2.31 per mmcf and $9.17 per mmcf at December 31, 2001 and December 31, 2000, respectively. Future income tax expenses have been computed considering available carryforwards and credits and the appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by SFAS No. 69. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs. Of the $1,114 million of future development costs, $230 million, $233 million and $188 million are estimated to be spent in 2002, 2003 and 2004, respectively.

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

SUPPLEMENTAL OIL AND GAS DISCLOSURES -- (CONCLUDED)
(UNAUDITED)

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	AT DECEMBER 31, 2001
	(MILLIONS)
Future cash inflows	$7,334
Less:	
Future production costs	1,958
Future development costs	1,114
Future income tax provisions	1,317
Future net cash flows	2,945
Less 10 percent annual discount for estimated timing of cash flows	1,513
Standardized measure of discounted future net cash flows	$1,432

SOURCES OF CHANGE IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	2001
	(MILLIONS)
Standardized measure of discounted future net cash flows beginning of period	$ 2,720
Changes during the year:	
Sales of oil and gas produced, net of operating costs	(270)
Net change in prices and production costs	(3,945)
Extensions, discoveries and improved recovery, less estimated future costs	153
Development costs incurred during year	199
Changes in estimated future development costs	(41)
Purchase of reserves in place, less estimated future costs	1,069
Sales of reserves in place, less estimated future costs	(8)
Revisions of previous quantity estimates	(43)
Accretion of discount	426
Net change in income taxes	1,077
Other	95
Net changes	(1,288)
Standardized measure of discounted future net cash flows end of period	$ 1,432

THE WILLIAMS COMPANIES, INC.

SCHEDULE II -- VALUATION AND QUALIFYING ACCOUNTS

	BEGINNING BALANCE	ADDITIONS: CHARGED TO COSTS AND EXPENSES	ADDITIONS: OTHER	DEDUCTIONS	ENDING BALANCE
			(MILLIONS)		
Year ended December 31, 2001:					
Allowance for doubtful accounts --					
Accounts and notes receivable(a).........	$ 9.8	$100.0	$145.6(e)	$(1.2)(c)	$256.6
Other noncurrent assets(a)...............	--	103.2	--	--	103.2
Price-risk management credit reserves(a)....	60.9	728.5	(141.2)(f)	--	648.2
Refining and processing plant major maintenance accrual(b)..................	13.9	10.2	--	11.1(d)	13.0
Year ended December 31, 2000:					
Allowance for doubtful accounts --					
Receivables(a)...........................	3.5	4.7	--	(1.6)(c)	9.8
Price-risk management credit reserves(a)....	10.6	50.3	--	--	60.9
Refining and processing plant major maintenance accrual(b)..................	7.6	8.4	--	2.1(d)	13.9
Year ended December 31, 1999:					
Allowance for doubtful accounts --					
Receivables(a)...........................	10.6	(.1)	--	7.0(c)	3.5
Price-risk management credit reserves(a)....	13.0	(2.4)	--	--	10.6
Refining and processing plant major maintenance accrual(b)..................	5.3	7.8	3.9(g)	9.4(d)	7.6

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(a) Deducted from related assets.

(b) Included in liabilities.

(c) Represents balances written off, net of recoveries and reclassifications.

(d) Represents payments made.

(e) Reflects a reclassification of the reserve related to Enron from Price-risk management credit reserves to Allowance for doubtful accounts -- Receivables (see Note 19 of Notes to Consolidated Financial Statements) and amounts related to acquisitions of businesses.

(f) Reflects a reclassification of the reserve related to Enron from Price-risk management credit reserves to Allowance for doubtful accounts -- Receivables (see Note 19 of Notes to Consolidated Financial Statements).

(g) Primarily relates to acquisitions of businesses.

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information regarding the directors and nominees for director of Williams required by Item 401 of Regulation S-K will be presented under the heading "Election of Directors" in Williams' Proxy Statement prepared for the solicitation of proxies in connection with the Annual Meeting of Stockholders of Williams for 2002 (the "Proxy Statement"), which information is incorporated by reference herein. Information regarding the executive officers of Williams is presented following Item 4 herein as permitted by General Instruction G(3) to Form 10-K and Instruction 3 to Item 401(b) of Regulation S-K. Information required by Item 405 of Regulation S-K is included under the heading "Compliance with Section 16(a) of the Securities Exchange Act of 1934" in the Proxy Statement, which information is incorporated by reference herein.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 402 of Regulation S-K regarding executive compensation is presented under the headings "Election of Directors" and "Executive Compensation and Other Information" in the Proxy Statement, which information is incorporated by reference herein. Notwithstanding the foregoing, the information provided under the headings "Compensation Committee Report on Executive Compensation" and "Stockholder Return Performance Presentation" in the Proxy Statement is not incorporated by reference herein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information regarding the security ownership of certain beneficial owners and management required by Item 403 of Regulation S-K is presented under the headings "Security Ownership of Certain Beneficial Owners and Management" in the Proxy Statement, which information is incorporated by reference herein.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information regarding certain relationships and related transactions required by Item 404 of Regulation S-K is presented under the heading "Certain Relationships and Related Transactions" in the Proxy Statement, which information is incorporated by reference herein.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) 1 and 2.

	PAGE
Covered by report of independent auditors:	
Consolidated statement of operations for each of the three years ended December 31, 2001	76
Consolidated balance sheet at December 31, 2001 and 2000	77
Consolidated statement of stockholders' equity for each of the three years ended December 31, 2001	78
Consolidated statement of cash flows for each of the three years ended December 31, 2001	79
Notes to consolidated financial statements	80
Schedule for each of the three years ended December 31, 2001:	
II -- Valuation and qualifying accounts	141
Not covered by report of independent auditors:	
Quarterly financial data (unaudited)	135
Supplemental oil and gas disclosures (unaudited)	137

All other schedules have been omitted since the required information is not present or is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and notes thereto.

(a) 3 and (c). The exhibits listed below are filed as part of this annual report.

EXHIBITS

EXHIBIT NO.		DESCRIPTION
2*	--	Agreement and Plan of Merger among Williams, Resources Acquisition Corp. and Barrett Resources Corporation dated as of May 7, 2001 (filed as Exhibit 2 to Form 10-Q filed May 15, 2001).
3(I)(a)*	--	Restated Certificate of Incorporation, as supplemented (filed as Exhibit 3(I)(a) to Form 10-Q filed May 15, 2001).
3(II)(a)*	--	Restated By-laws (filed as Exhibit 99.1 to Form 8-K filed January 19, 2000).
4(a)*	--	Form of Senior Debt Indenture between Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.1 to Form S-3 filed September 8, 1997).
(b)*	--	Form of Subordinated Debt Indenture between Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.2 to Form S-3 filed September 8, 1997).
(c)*	--	Form of Floating Rate Senior Note (filed as Exhibit 4.3 to Form S-3 filed September 8, 1997).
(d)*	--	Form of Fixed Rate Senior Note (filed as Exhibit 4.4 to Form S-3 filed September 8, 1997).
(e)*	--	Form of Floating Rate Subordinated Note (filed as Exhibit 4.5 to Form S-3 filed September 8, 1997).
(f)*	--	Form of Fixed Rate Subordinated Note (filed as Exhibit 4.6 to Form S-3 filed September 8, 1997).
(g)**	--	First Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of September 8, 2000.
(h)**	--	Second Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of December 7, 2000.
(i)**	--	Third Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee dated as of December 20, 2000.
(j)*	--	Fourth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(j) to Form 10-K for the fiscal year ended December 31, 2000).
(k)*	--	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(k) to Form 10-K for the fiscal year ended December 31, 2000).
(l)*	--	Sixth Supplemental Indenture dated January 14, 2002, between Williams and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to Form 8-K filed January 23, 2002).
(m)*	--	Registration Rights Agreement dated January 17, 2001, among Williams and UBS Warburg LLC, Credit Suisse First Boston, Lehman Brothers and the other parties listed therein, as Initial Purchasers (filed as Exhibit 4.4 to Form S-4 filed March 22, 2001).
(n)*	--	Note Purchase Agreement between Williams and parties listed therein dated January 17, 2001 (filed as Exhibit 10.1 to Form S-4 filed March 22, 2001).
(o)*	--	Form of Senior Debt Indenture between Williams and The Chase Manhattan Bank (formerly Chemical Bank), as Trustee (filed as Exhibit 4.1 to Form S-3 filed February 2, 1990).
(p)*	--	Indenture dated May 1, 1990, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated June 25, 1990).

EXHIBIT NO.		DESCRIPTION
(q)*	--	First Supplemental Indenture dated June 20, 1990, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated June 25, 1990).
(r)*	--	Second Supplemental Indenture dated November 29, 1990, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated December 7, 1990).
(s)*	--	Third Supplemental Indenture dated April 23, 1991, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated April 30, 1991).
(t)*	--	Fourth Supplemental Indenture dated August 22, 1991, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated August 27, 1991).
(u)*	--	Fifth Supplemental Indenture dated May 1, 1995, among Transco Energy Company, Williams and The Bank of New York, as Trustee (filed as Exhibit 4(l) to Form 10-K for the fiscal year ended December 31, 1998).
(v)*	--	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Williams Holdings of Delaware, Inc.'s Form 10-Q filed October 18, 1995).
(w)*	--	First Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Citibank, N.A., as Trustee (filed as Exhibit 4(o) to Form 10-K for the fiscal year ended December 31, 1999).
(x)*	--	Indenture dated March 31, 1990, between MAPCO Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4.0 to MAPCO Inc.'s Form 8-K filed February 19, 1991).
(y)*	--	First Supplemental Indenture dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4(f) to Williams Holdings of Delaware, Inc.'s Form 10-K for the fiscal year ended December 31, 1998).
(z)*	--	Second Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Bankers Trust Company, as Trustee (filed as Exhibit 4(p) to Form 10-K for the fiscal year ended December 31, 1999).
(aa)*	--	Senior Indenture dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.5.1 to MAPCO Inc.'s Amendment No. 1 to Form S-3 dated February 25, 1997).
(bb)*	--	Supplemental Indenture No. 1 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.(o) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
(cc)*	--	Supplemental Indenture No. 2 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.(p) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
(dd)*	--	Supplemental Indenture No. 3 dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(j) to Williams Holdings of Delaware, Inc.'s Form 10-K for the fiscal year ended December 31, 1998).
(ee)*	--	Supplemental Indenture No. 4 dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(q) to Form 10-K for the fiscal year ended December 31, 1999).
(ff)*	--	Revised Form of Indenture between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee, with respect to Senior Notes including specimen of 7.55% Senior Notes (filed as Exhibit 4.1 to Barrett Resources Corporation's Amendment No. 2 to Registration Statement on Form S-3 filed February 10, 1997).

EXHIBIT NO.		DESCRIPTION
(gg)*	--	First Supplemental Indenture dated 2001, between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee (filed as Exhibit 4.3 to Form 10-Q filed November 13, 2001).
(hh)*	--	Second Supplemental Indenture dated as of August 2, 2001, among Barrett Resources Corporation, as Issuer, Resources Acquisition Corp., The Williams Companies, Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4.4 to Form 10-Q filed November 13, 2001).
(ii)*	--	Rights Agreement dated as of February 6, 1996, between Williams and First Chicago Trust Company of New York (filed as Exhibit 4 to Form 8-K filed January 24, 1996).
(jj)*	--	Certificate of Increase of Authorized Number of Shares of Series A Junior Participating Preferred Stock (filed as Exhibit 3(f) to Form 10-K for the fiscal year ended December 31, 1995).
(kk)*	--	Certificate of Increase of Authorized Number of Shares of Series A Junior Participating Preferred Stock (filed as Exhibit 3(g) to Form 10-K for the fiscal year ended December 31, 1997).
(ll)*	--	Form of Note (filed as Exhibit 4.2 and included in Exhibit 4.1 to Form 8-K filed January 23, 2002).
(mm)*	--	Purchase Contract Agreement dated January 14, 2002, between Williams and JPMorgan Chase Bank, as Purchase Contract Agent (filed as Exhibit 4.3 to Form 8-K filed January 23, 2002).
(nn)*	--	Form of Income PACS Certificate (filed as Exhibit 4.4 and included in Exhibit 4.3 to Form 8-K filed January 23, 2002).
(oo)*	--	Pledge Agreement dated January 14, 2002, among Williams, JPMorgan Chase Bank, as Collateral Agent, and JPMorgan Chase Bank, as Purchase Contract Agent (filed as Exhibit 4.5 to Form 8-K filed January 23, 2002).
(pp)*	--	Remarketing Agreement dated January 14, 2002, among Williams, JPMorgan Chase Bank, as Purchase Contract Agent, and Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Remarketing Agent (filed as Exhibit 4.6 to Form 8-K filed January 23, 2002).
(qq)*	--	Trust Indenture dated as of August 13, 2001 among Kern River Funding Corporation, as Issuer, Kern River Gas Transmission Company, as Guarantor, and The Chase Manhattan Bank, as Trustee (filed as Exhibit 4(qq) to Form 10-K for the fiscal year ended December 31, 2001).
(rr)*	--	Indenture dated as of August 27, 2001, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A. (filed as Exhibit 4.1 to Transco's Registration Statement on Form S-4 filed November 8, 2001).
10(a)*	--	Credit Agreement dated as July 25, 2000, among Williams and certain of its subsidiaries, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 4.1 to Form 10-Q filed August 11, 2000).
(b)*	--	Waiver and First Amendment to Credit Agreement dated as of January 31, 2001, to Credit Agreement dated July 25, 2000, among Williams and certain of its subsidiaries, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 4(jj) to Form 10-K for the fiscal year ended December 31, 2000).
(c)*	--	Second Amendment to Credit Agreement dated as of February 7, 2002, among Williams and certain of its subsidiaries, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 10(c) to Form 10-K for the fiscal year ended December 31, 2001).
(d)*	--	Credit Agreement dated as of July 25, 2000, among Williams, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 4.2 to Form 10-Q filed August 11, 2000).
(e)*	--	Waiver and First Amendment to Credit Agreement dated as of January 31, 2001, to Credit Agreement dated July 25, 2000, among Williams, the banks named therein and Citibank, N.A., as agent.

EXHIBIT NO.		DESCRIPTION
(f)*	--	Limited Waiver and Second Amendment to Credit Agreement dated July 24, 2001, among Williams, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 10(f) to Form 10-K for the fiscal year ended December 31, 2001).
(g)*	--	Third Amendment to Credit Agreement dated as of February 7, 2002, among Williams, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 10(g) to Form 10-K for the fiscal year ended December 31, 2001).
(h)*	--	U.S. $400,000,000 Term Loan Agreement dated April 7, 2000, among Williams, the lenders named therein and Credit Lyonnais New York Branch, as administrative agent (filed as Exhibit 4(r) to Form 10-K for the fiscal year ended December 31, 1999).
(i)*	--	First Amendment dated as of August 21, 2000, to Term Loan Agreement dated April 7, 2000, among Williams, the lenders named therein and Credit Lyonnais New York Branch, as administrative agent (filed as Exhibit 4(nn) to Form 10-K for the fiscal year ended December 31, 2000).
(j)*	--	Form of Waiver and Second Amendment dated as of January 31, 2001, to Term Loan Agreement dated April 7, 2000, among Williams, the lenders named therein and Credit Lyonnais New York Branch, as administrative agent (filed as Exhibit 4(oo) to Form 10-K for the fiscal year ended December 31, 2000).
(k)*	--	Third Amendment dated as of February 7, 2002, to Term Loan Agreement dated April 7, 2000, among Williams, the lenders named therein and Credit Lyonnais New York Branch, as administrative agent (filed as Exhibit 10(k) to Form 10-K for the fiscal year ended December 31, 2001).
(l)*	--	Underwriting Agreement dated January 16, 2001, among Williams and the underwriters named therein (filed as Exhibit 10(a) to Form 10-K for the fiscal year ended December 31, 2000).
(m)*	--	Participation Agreement among Williams, Williams Communications Group, Inc., Williams Communications, LLC, WCG Note Trust, WCG Note Corp., Inc., Williams Share Trust, United States Trust Company of New York and Wilmington Trust Company dated as of March 22, 2001 (filed as Exhibit 10(a) to Form 10-Q filed May 15, 2001).
(n)*	--	Williams Preferred Stock Remarketing, Registration Rights and Support Agreement among Williams, Williams Share Trust, WCG Note Trust, United States Trust Company of New York and Credit Suisse First Boston Corporation dated as of March 28, 2001 (filed as Exhibit 10(b) to Form 10-Q filed May 15, 2001).
(o)*	--	Indenture dated as of March 28, 2001, among WCG Note Trust, Issuer, WCG Note Corp., Inc., Co-Issuer, and United States Trust Company of New York, Indenture Trustee and Securities Intermediary (filed as Exhibit 10.8 to Form 10-Q filed November 13, 2001).
(p)*	--	Intercreditor Agreement dated as of September 8, 1999, among Williams, Williams Communications Group, Inc., Williams Communications, LLC and Bank of America N.A. (filed as Exhibit 10.7 to Form 10-Q filed November 13, 2001).
(q)*	--	Amendment and Consent dated as of August 17, 2000, to the Amended and Restated Participation Agreement, attaching as Exhibit A the Second Amended and Restated Guaranty Agreement dated as of August 17, 2000, between Williams, State Street Bank and Trust Company of Connecticut, National Association, State Street Bank and Trust Company and Citibank, N.A., as Agent (filed as Exhibit 10(q) to Form 10-K for the fiscal year ended December 31, 2001).
(r)*	--	Amendment, Waiver and Consent dated as of January 31, 2001, to Second Amended and Restated Guaranty Agreement between Williams, State Street Bank and Trust Company of Connecticut, National Association, State Street Bank and Trust Company and Citibank, N.A., as Agent (filed as Exhibit 10(r) to Form 10-K for the fiscal year ended December 31, 2001).

EXHIBIT NO.		DESCRIPTION
(s)*	--	Amendment and Consent dated as of February 7, 2002, to Second Amended and Restated Guaranty Agreement between Williams, State Street Bank and Trust Company of Connecticut, National Association, State Street Bank and Trust Company and Citibank, N.A., as Agent (filed as Exhibit 10(s) to Form 10-K for the fiscal year ended December 31, 2001).
(t)*	--	Membership Interest Purchase Agreement dated as of September 13, 2001, between Williams Communications, LLC and Williams Aircraft, Inc (filed as Exhibit 10(t) to Form 10-K for the fiscal year ended December 31, 2001).
(u)*	--	Aircraft Dry Lease, N352WC, dated as of September 13, 2001, between Williams Communications Aircraft, LLC and Williams Communications, LLC (filed as Exhibit 10(u) to Form 10-K for the fiscal year ended December 31, 2001).
(v)*	--	Aircraft Dry Lease, N358WC, dated as of September 13, 2001, between Williams Communications Aircraft, LLC and Williams Communications, LLC (filed as Exhibit 10(v) to Form 10-K for the fiscal year ended December 31, 2001).
(w)*	--	Aircraft Dry Lease, N359WC, dated as of September 13, 2001, between Williams Communications Aircraft, LLC and Williams Communications, LLC (filed as Exhibit 10(w) to Form 10-K for the fiscal year ended December 31, 2001).
(x)*	--	Agreement of Purchase and Sale dated as of September 13, 2001, among Williams Technology Center, LLC, Williams Headquarters Building Company and Williams Communications, LLC (filed as Exhibit 10(x) to Form 10-K for the fiscal year ended December 31, 2001).
(y)*	--	Master Lease dated as of September 13, 2001, among Williams Technology Center, LLC, Williams Headquarters Building Company and Williams Communications, LLC (filed as Exhibit 10(y) to Form 10-K for the fiscal year ended December 31, 2001).
(z)*	--	The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 1988 (filed as Exhibit 10(iii)(c) to Form 10-K for the fiscal year ended December 31, 1987).
(aa)*	--	Form of The Williams Companies, Inc. Change in Control Protection Plan among Williams and employees (filed as Exhibit 10(iii)(e) to Form 10-K for the fiscal year ended December 31, 1989).
(bb)*	--	The Williams Companies, Inc. 1985 Stock Option Plan (filed as Exhibit A to the Proxy Statement dated March 13, 1985).
(cc)*	--	The Williams Companies, Inc. 1988 Stock Option Plan for Non-Employee Directors (filed as Exhibit A to the Proxy Statement dated March 14, 1988).
(dd)*	--	The Williams Companies, Inc. 1990 Stock Plan (filed as Exhibit A to the Proxy Statement dated March 12, 1990).
(ee)*	--	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed as Exhibit 10(iii)(g) to Form 10-K for the fiscal year ended December 31, 1995).
(ff)*	--	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to the Proxy Statement dated March 27, 1996).
(gg)*	--	The Williams Companies, Inc. 1996 Stock Plan for Non-Employee Directors (filed as Exhibit B to the Proxy Statement dated March 27, 1996).
(hh)*	--	Indemnification Agreement effective as of August 1, 1986, among Williams, members of the Board of Directors and certain officers of Williams (filed as Exhibit 10(iii)(e) to Form 10-K for the year ended December 31, 1986).
(ii)*	--	The Williams International Stock Plan (filed as Exhibit 10(iii)(l) to Form 10-K for the fiscal year ended December 31, 1998).
(jj)*	--	Form of Stock Option Secured Promissory Note and Pledge Agreement among Williams and certain employees, officers and non-employee directors (filed as Exhibit 10(iii)(m) to Form 10-K for the fiscal year ended December 31, 1998).
(kk)*	--	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to Form S-8 filed August 1, 2001).
(ll)*	--	Amended and Restated Separation Agreement dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.1 to Form 8-K filed May 3, 2001).

EXHIBIT NO.		DESCRIPTION
(mm)*	--	Amended and Restated Administrative Services Agreement dated April 23, 2001, between Williams and certain subsidiaries of Williams and Williams Communications Group, Inc., and certain subsidiaries of Communications (filed as Exhibit 99.2 to Form 8-K filed May 3, 2001).
(nn)*	--	Tax Sharing Agreement dated as of September 30, 1999, and amended and restated as of April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.3 to Form 8-K filed May 3, 2001).
(oo)*	--	Amended and Restated Indemnification Agreement dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.4 to Form 8-K filed May 3, 2001).
(pp)*	--	Shareholder Agreement dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.5 to Form 8-K filed May 3, 2001).
(qq)*	--	Amended and Restated Employee Benefits Agreement dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.6 to Form 8-K filed May 3, 2001).
(rr)*	--	Deferral Letter dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.7 to Form 8-K filed May 3, 2001).
(ss)*	--	Underwriting Agreement dated January 7, 2002, between Williams and the several underwriters named therein (filed as Exhibit 1.1 to Form 8-K filed January 23, 2002).
12*	--	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements (filed as Exhibit 12 to Form 10-K for fiscal year ended December 31, 2001).
20*	--	Definitive Proxy Statement of Williams for 2002 (filed on Schedule 14A filed March 29, 2002).
21*	--	Subsidiaries of the registrant (filed as Exhibit 21 to Form 10-K for fiscal year ended December 31, 2001).
23*	--	Consent of Independent Auditors, Ernst & Young LLP (filed as Exhibit 23 to Form 10-K for fiscal year ended December 31, 2001).
24*	--	Power of Attorney together with certified resolution (filed as Exhibit 24 to Form 10-K for fiscal year ended December 31, 2001).

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* Each such exhibit has heretofore been filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

** Williams agrees upon request to furnish each such exhibit to the Securities and Exchange Commission. The total amount of the securities authorized under each such exhibit does not exceed ten percent of the total assets of Williams and its subsidiaries taken as a whole.

(b) Reports on Form 8-K.

On November 29, 2001, Williams filed a current report on Form 8-K to reaffirm its 2001 earnings guidance and 15 percent annual earnings growth.

On December 19, 2001, Williams filed a current report on Form 8-K to announce steps to further strengthen its balance sheet and liquidity profile.

On December 21, 2001, Williams filed a current report on Form 8-K to announce that international rating agencies Fitch, Inc., Standard & Poor's and Moody's Investors Service had reaffirmed Williams' investment-grade ratings.

(d) The financial statements of partially owned companies are not presented herein since none of them individually, or in the aggregate, constitute a significant subsidiary.

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.

THE WILLIAMS COMPANIES, INC.
(Registrant)

By: /s/ SUZANNE H. COSTIN

Suzanne H. Costin
Attorney-in-fact

Date: May 28, 2002

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

SIGNATURE	TITLE	DATE
/s/ STEVEN J. MALCOLM* Steven J. Malcolm	President, Chief Executive Officer and Director (Principal Executive Officer)	May 28, 2002
/s/ JACK D. MCCARTHY* Jack D. McCarthy	Senior Vice President -- Finance (Principal Financial Officer)	May 28, 2002
/s/ GARY R. BELITZ* Gary R. Belitz	Controller (Principal Accounting Officer)	May 28, 2002
/s/ HUGH M. CHAPMAN* Hugh M. Chapman	Director	May 28, 2002
/s/ THOMAS H. CRUIKSHANK* Thomas H. Cruikshank	Director	May 28, 2002
/s/ WILLIAM E. GREEN* William E. Green	Director	May 28, 2002
/s/ IRA D. HALL* Ira D. Hall	Director	May 28, 2002
/s/ W.R. HOWELL* W.R. Howell	Director	May 28, 2002
/s/ JAMES C. LEWIS* James C. Lewis	Director	May 28, 2002
/s/ CHARLES M. LILLIS* Charles M. Lillis	Director	May 28, 2002

SIGNATURE	TITLE	DATE
/s/ GEORGE A. LORCH* George A. Lorch	Director	May 28, 2002
/s/ FRANK T. MACINNIS* Frank T. MacInnis	Director	May 28, 2002
/s/ GORDON R. PARKER* Gordon R. Parker	Director	May 28, 2002
/s/ JANICE D. STONEY* Janice D. Stoney	Director	May 28, 2002
/s/ JOSEPH H. WILLIAMS* Joseph H. Williams	Director	May 28, 2002
*By: /s/ SUZANNE H. COSTIN Suzanne H. Costin Attorney-in-fact		May 28, 2002

INDEX TO EXHIBITS

EXHIBIT NO.		DESCRIPTION
2*	--	Agreement and Plan of Merger among Williams, Resources Acquisition Corp. and Barrett Resources Corporation dated as of May 7, 2001 (filed as Exhibit 2 to Form 10-Q filed May 15, 2001).
3(I)(a)*	--	Restated Certificate of Incorporation, as supplemented (filed as Exhibit 3(I)(a) to Form 10-Q filed May 15, 2001).
3(II)(a)*	--	Restated By-laws (filed as Exhibit 99.1 to Form 8-K filed January 19, 2000).
4(a)*	--	Form of Senior Debt Indenture between Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.1 to Form S-3 filed September 8, 1997).
(b)*	--	Form of Subordinated Debt Indenture between Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.2 to Form S-3 filed September 8, 1997).
(c)*	--	Form of Floating Rate Senior Note (filed as Exhibit 4.3 to Form S-3 filed September 8, 1997).
(d)*	--	Form of Fixed Rate Senior Note (filed as Exhibit 4.4 to Form S-3 filed September 8, 1997).
(e)*	--	Form of Floating Rate Subordinated Note (filed as Exhibit 4.5 to Form S-3 filed September 8, 1997).
(f)*	--	Form of Fixed Rate Subordinated Note (filed as Exhibit 4.6 to Form S-3 filed September 8, 1997).
(g)**	--	First Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of September 8, 2000.
(h)**	--	Second Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of December 7, 2000.
(i)**	--	Third Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee dated as of December 20, 2000.
(j)*	--	Fourth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(j) to Form 10-K for the fiscal year ended December 31, 2000).
(k)*	--	Fifth Supplemental Indenture between Williams and Bank One Trust Company, N.A., as Trustee, dated as of January 17, 2001 (filed as Exhibit 4(k) to Form 10-K for the fiscal year ended December 31, 2000).
(l)*	--	Sixth Supplemental Indenture dated January 14, 2002, between Williams and Bank One Trust Company, National Association, as Trustee (filed as Exhibit 4.1 to Form 8-K filed January 23, 2002).
(m)*	--	Registration Rights Agreement dated January 17, 2001, among Williams and UBS Warburg LLC, Credit Suisse First Boston, Lehman Brothers and the other parties listed therein, as Initial Purchasers (filed as Exhibit 4.4 to Form S-4 filed March 22, 2001).
(n)*	--	Note Purchase Agreement between Williams and parties listed therein dated January 17, 2001 (filed as Exhibit 10.1 to Form S-4 filed March 22, 2001).
(o)*	--	Form of Senior Debt Indenture between Williams and The Chase Manhattan Bank (formerly Chemical Bank), as Trustee (filed as Exhibit 4.1 to Form S-3 filed February 2, 1990).
(p)*	--	Indenture dated May 1, 1990, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated June 25, 1990).
(q)*	--	First Supplemental Indenture dated June 20, 1990, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated June 25, 1990).
(r)*	--	Second Supplemental Indenture dated November 29, 1990, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated December 7, 1990).

EXHIBIT NO.		DESCRIPTION
(s)*	--	Third Supplemental Indenture dated April 23, 1991, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated April 30, 1991).
(t)*	--	Fourth Supplemental Indenture dated August 22, 1991, between Transco Energy Company and The Bank of New York, as Trustee (filed as an Exhibit to Transco Energy Company's Form 8-K dated August 27, 1991).
(u)*	--	Fifth Supplemental Indenture dated May 1, 1995, among Transco Energy Company, Williams and The Bank of New York, as Trustee (filed as Exhibit 4(l) to Form 10-K for the fiscal year ended December 31, 1998).
(v)*	--	Form of Senior Debt Indenture between Williams Holdings of Delaware, Inc. and Citibank, N.A., as Trustee (filed as Exhibit 4.1 to Williams Holdings of Delaware, Inc.'s Form 10-Q filed October 18, 1995).
(w)*	--	First Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Citibank, N.A., as Trustee (filed as Exhibit 4(o) to Form 10-K for the fiscal year ended December 31, 1999).
(x)*	--	Indenture dated March 31, 1990, between MAPCO Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4.0 to MAPCO Inc.'s Form 8-K filed February 19, 1991).
(y)*	--	First Supplemental Indenture dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4(f) to Williams Holdings of Delaware, Inc.'s Form 10-K for the fiscal year ended December 31, 1998).
(z)*	--	Second Supplemental Indenture dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Bankers Trust Company, as Trustee (filed as Exhibit 4(p) to Form 10-K for the fiscal year ended December 31, 1999).
(aa)*	--	Senior Indenture dated February 25, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.5.1 to MAPCO Inc.'s Amendment No. 1 to Form S-3 dated February 25, 1997).
(bb)*	--	Supplemental Indenture No. 1 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.(o) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
(cc)*	--	Supplemental Indenture No. 2 dated March 5, 1997, between MAPCO Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4.(p) to MAPCO Inc.'s Form 10-K for the fiscal year ended December 31, 1997).
(dd)*	--	Supplemental Indenture No. 3 dated March 31, 1998, among MAPCO Inc., Williams Holdings of Delaware, Inc. and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(j) to Williams Holdings of Delaware, Inc.'s Form 10-K for the fiscal year ended December 31, 1998).
(ee)*	--	Supplemental Indenture No. 4 dated as of July 31, 1999, among Williams Holdings of Delaware, Inc., Williams and Bank One Trust Company, N.A. (formerly The First National Bank of Chicago), as Trustee (filed as Exhibit 4(q) to Form 10-K for the fiscal year ended December 31, 1999).
(ff)*	--	Revised Form of Indenture between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee, with respect to Senior Notes including specimen of 7.55% Senior Notes (filed as Exhibit 4.1 to Barrett Resources Corporation's Amendment No. 2 to Registration Statement on Form S-3 filed February 10, 1997).
(gg)*	--	First Supplemental Indenture dated 2001, between Barrett Resources Corporation, as Issuer, and Bankers Trust Company, as Trustee (filed as Exhibit 4.3 to Form 10-Q filed November 13, 2001).
(hh)*	--	Second Supplemental Indenture dated as of August 2, 2001, among Barrett Resources Corporation, as Issuer, Resources Acquisition Corp., The Williams Companies, Inc. and Bankers Trust Company, as Trustee (filed as Exhibit 4.4 to Form 10-Q filed November 13, 2001).

EXHIBIT NO.		DESCRIPTION
(ii)*	--	Rights Agreement dated as of February 6, 1996, between Williams and First Chicago Trust Company of New York (filed as Exhibit 4 to Form 8-K filed January 24, 1996).
(jj)*	--	Certificate of Increase of Authorized Number of Shares of Series A Junior Participating Preferred Stock (filed as Exhibit 3(f) to Form 10-K for the fiscal year ended December 31, 1995).
(kk)*	--	Certificate of Increase of Authorized Number of Shares of Series A Junior Participating Preferred Stock (filed as Exhibit 3(g) to Form 10-K for the fiscal year ended December 31, 1997).
(ll)*	--	Form of Note (filed as Exhibit 4.2 and included in Exhibit 4.1 to Form 8-K filed January 23, 2002).
(mm)*	--	Purchase Contract Agreement dated January 14, 2002, between Williams and JPMorgan Chase Bank, as Purchase Contract Agent (filed as Exhibit 4.3 to Form 8-K filed January 23, 2002).
(nn)*	--	Form of Income PACS Certificate (filed as Exhibit 4.4 and included in Exhibit 4.3 to Form 8-K filed January 23, 2002).
(oo)*	--	Pledge Agreement dated January 14, 2002, among Williams, JPMorgan Chase Bank, as Collateral Agent, and JPMorgan Chase Bank, as Purchase Contract Agent (filed as Exhibit 4.5 to Form 8-K filed January 23, 2002).
(pp)*	--	Remarketing Agreement dated January 14, 2002, among Williams, JPMorgan Chase Bank, as Purchase Contract Agent, and Merrill Lynch & Co., Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Remarketing Agent (filed as Exhibit 4.6 to Form 8-K filed January 23, 2002).
(qq)*	--	Trust Indenture dated as of August 13, 2001 among Kern River Funding Corporation, as Issuer, Kern River Gas Transmission Company, as Guarantor, and The Chase Manhattan Bank as Trustee (filed as Exhibit 4(qq) to Form 10-K for the fiscal year ended December 31, 2001).
(rr)*	--	Indenture dated as of August 27, 2001, between Transcontinental Gas Pipe Line Corporation and Citibank, N.A. (filed as Exhibit 4.1 to Transco's Registration Statement on Form S-4 filed November 8, 2001).
10(a)*	--	Credit Agreement dated as July 25, 2000, among Williams and certain of its subsidiaries, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 4.1 to Form 10-Q filed August 11, 2000).
(b)*	--	Waiver and First Amendment to Credit Agreement dated as of January 31, 2001, to Credit Agreement dated July 25, 2000, among Williams and certain of its subsidiaries, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 4(jj) to Form 10-K for the fiscal year ended December 31, 2000).
(c)*	--	Second Amendment to Credit Agreement dated as of February 7, 2002, among Williams and certain of its subsidiaries, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 10(c) to Form 10-K for the fiscal year ended December 31, 2001).
(d)*	--	Credit Agreement dated as of July 25, 2000, among Williams, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 4.2 to Form 10-Q filed August 11, 2000).
(e)*	--	Waiver and First Amendment to Credit Agreement dated as of January 31, 2001, to Credit Agreement dated July 25, 2000, among Williams, the banks named therein and Citibank, N.A., as agent.
(f)*	--	Limited Waiver and Second Amendment to Credit Agreement dated July 24, 2001, among Williams, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 10(f) to Form 10-K for the fiscal year ended December 31, 2001).
(g)*	--	Third Amendment to Credit Agreement dated as of February 7, 2002, among Williams, the banks named therein and Citibank, N.A., as agent (filed as Exhibit 10(g) to Form 10-K for the fiscal year ended December 31, 2001).

EXHIBIT NO.		DESCRIPTION
(h)*	--	U.S. $400,000,000 Term Loan Agreement dated April 7, 2000, among Williams, the lenders named therein and Credit Lyonnais New York Branch, as administrative agent (filed as Exhibit 4(r) to Form 10-K for the fiscal year ended December 31, 1999).
(i)*	--	First Amendment dated as of August 21, 2000, to Term Loan Agreement dated April 7, 2000, among Williams, the lenders named therein and Credit Lyonnais New York Branch, as administrative agent (filed as Exhibit 4(nn) to Form 10-K for the fiscal year ended December 31, 2000).
(j)*	--	Form of Waiver and Second Amendment dated as of January 31, 2001, to Term Loan Agreement dated April 7, 2000, among Williams, the lenders named therein and Credit Lyonnais New York Branch, as administrative agent (filed as Exhibit 4(oo) to Form 10-K for the fiscal year ended December 31, 2000).
(k)*	--	Third Amendment dated as of February 7, 2002, to Term Loan Agreement dated April 7, 2000, among Williams, the lenders named therein and Credit Lyonnais New York Branch, as administrative agent (filed as Exhibit 10(k) to Form 10-K for the fiscal year ended December 31, 2001).
(l)*	--	Underwriting Agreement dated January 16, 2001, among Williams and the underwriters named therein (filed as Exhibit 10(a) to Form 10-K for the fiscal year ended December 31, 2000).
(m)*	--	Participation Agreement among Williams, Williams Communications Group, Inc., Williams Communications, LLC, WCG Note Trust, WCG Note Corp., Inc., Williams Share Trust, United States Trust Company of New York and Wilmington Trust Company dated as of March 22, 2001 (filed as Exhibit 10(a) to Form 10-Q filed May 15, 2001).
(n)*	--	Williams Preferred Stock Remarketing, Registration Rights and Support Agreement among Williams, Williams Share Trust, WCG Note Trust, United States Trust Company of New York and Credit Suisse First Boston Corporation dated as of March 28, 2001 (filed as Exhibit 10(b) to Form 10-Q filed May 15, 2001).
(o)*	--	Indenture dated as of March 28, 2001, among WCG Note Trust, Issuer, WCG Note Corp., Inc., Co-Issuer, and United States Trust Company of New York, Indenture Trustee and Securities Intermediary (filed as Exhibit 10.8 to Form 10-Q filed November 13, 2001).
(p)*	--	Intercreditor Agreement dated as of September 8, 1999, among Williams, Williams Communications Group, Inc., Williams Communications, LLC and Bank of America N.A. (filed as Exhibit 10.7 to Form 10-Q filed November 13, 2001).
(q)*	--	Amendment and Consent dated as of August 17, 2000, to the Amended and Restated Participation Agreement, attaching as Exhibit A the Second Amended and Restated Guaranty Agreement dated as of August 17, 2000, between Williams, State Street Bank and Trust Company of Connecticut, National Association, State Street Bank and Trust Company and Citibank, N.A., as Agent (filed as Exhibit 10(q) to Form 10-K for the fiscal year ended December 31, 2001).
(r)*	--	Amendment, Waiver and Consent dated as of January 31, 2001, to Second Amended and Restated Guaranty Agreement between Williams, State Street Bank and Trust Company of Connecticut, National Association, State Street Bank and Trust Company and Citibank, N.A., as Agent (filed as Exhibit 10(r) to Form 10-K for the fiscal year ended December 31, 2001).
(s)*	--	Amendment and Consent dated as of February 7, 2002, to Second Amended and Restated Guaranty Agreement between Williams, State Street Bank and Trust Company of Connecticut, National Association, State Street Bank and Trust Company and Citibank, N.A., as Agent (filed as Exhibit 10(s) to Form 10-K for the fiscal year ended December 31, 2001).
(t)*	--	Membership Interest Purchase Agreement dated as of September 13, 2001, between Williams Communications, LLC and Williams Aircraft, Inc. (filed as Exhibit 10(t) to Form 10-K for the fiscal year ended December 31, 2001).

EXHIBIT NO.		DESCRIPTION
(u)*	--	Aircraft Dry Lease, N352WC, dated as of September 13, 2001, between Williams Communications Aircraft, LLC and Williams Communications, LLC (filed as Exhibit 10(u) to Form 10-K for the fiscal year ended December 31, 2001).
(v)*	--	Aircraft Dry Lease, N358WC, dated as of September 13, 2001, between Williams Communications Aircraft, LLC and Williams Communications, LLC (filed as Exhibit 10(v) to Form 10-K for the fiscal year ended December 31, 2001).
(w)*	--	Aircraft Dry Lease, N359WC, dated as of September 13, 2001, between Williams Communications Aircraft, LLC and Williams Communications, LLC (filed as Exhibit 10(w) to Form 10-K for the fiscal year ended December 31, 2001).
(x)*	--	Agreement of Purchase and Sale dated as of September 13, 2001, among Williams Technology Center, LLC, Williams Headquarters Building Company and Williams Communications, LLC (filed as Exhibit 10(x) to Form 10-K for the fiscal year ended December 31, 2001).
(y)*	--	Master Lease dated as of September 13, 2001, among Williams Technology Center, LLC, Williams Headquarters Building Company and Williams Communications, LLC (filed as Exhibit 10(y) to Form 10-K for the fiscal year ended December 31, 2001).
(z)*	--	The Williams Companies, Inc. Supplemental Retirement Plan effective as of January 1, 1988 (filed as Exhibit 10(iii)(c) to Form 10-K for the fiscal year ended December 31, 1987).
(aa)*	--	Form of The Williams Companies, Inc. Change in Control Protection Plan among Williams and employees (filed as Exhibit 10(iii)(e) to Form 10-K for the fiscal year ended December 31, 1989).
(bb)*	--	The Williams Companies, Inc. 1985 Stock Option Plan (filed as Exhibit A to the Proxy Statement dated March 13, 1985).
(cc)*	--	The Williams Companies, Inc. 1988 Stock Option Plan for Non-Employee Directors (filed as Exhibit A to the Proxy Statement dated March 14, 1988).
(dd)*	--	The Williams Companies, Inc. 1990 Stock Plan (filed as Exhibit A to the Proxy Statement dated March 12, 1990).
(ee)*	--	The Williams Companies, Inc. Stock Plan for Non-Officer Employees (filed as Exhibit 10(iii)(g) to Form 10-K for the fiscal year ended December 31, 1995).
(ff)*	--	The Williams Companies, Inc. 1996 Stock Plan (filed as Exhibit A to the Proxy Statement dated March 27, 1996).
(gg)*	--	The Williams Companies, Inc. 1996 Stock Plan for Non-Employee Directors (filed as Exhibit B to the Proxy Statement dated March 27, 1996).
(hh)*	--	Indemnification Agreement effective as of August 1, 1986, among Williams, members of the Board of Directors and certain officers of Williams (filed as Exhibit 10(iii)(e) to Form 10-K for the year ended December 31, 1986).
(ii)*	--	The Williams International Stock Plan (filed as Exhibit 10(iii)(l) to Form 10-K for the fiscal year ended December 31, 1998).
(jj)*	--	Form of Stock Option Secured Promissory Note and Pledge Agreement among Williams and certain employees, officers and non-employee directors (filed as Exhibit 10(iii)(m) to Form 10-K for the fiscal year ended December 31, 1998).
(kk)*	--	The Williams Companies, Inc. 2001 Stock Plan (filed as Exhibit 4.1 to Form S-8 filed August 1, 2001).
(ll)*	--	Amended and Restated Separation Agreement dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.1 to Form 8-K filed May 3, 2001).
(mm)*	--	Amended and Restated Administrative Services Agreement dated April 23, 2001, between Williams and certain subsidiaries of Williams and Williams Communications Group, Inc., and certain subsidiaries of Communications (filed as Exhibit 99.2 to Form 8-K filed May 3, 2001).
(nn)*	--	Tax Sharing Agreement dated as of September 30, 1999, and amended and restated as of April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.3 to Form 8-K filed May 3, 2001).

EXHIBIT NO.		DESCRIPTION
(oo)*	--	Amended and Restated Indemnification Agreement dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.4 to Form 8-K filed May 3, 2001).
(pp)*	--	Shareholder Agreement dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.5 to Form 8-K filed May 3, 2001).
(qq)*	--	Amended and Restated Employee Benefits Agreement dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.6 to Form 8-K filed May 3, 2001).
(rr)*	--	Deferral Letter dated April 23, 2001, between Williams and Williams Communications Group, Inc. (filed as Exhibit 99.7 to Form 8-K filed May 3, 2001).
(ss)*	--	Underwriting Agreement dated January 7, 2002, between Williams and the several underwriters named therein (filed as Exhibit 1.1 to Form 8-K filed January 23, 2002).
12*	--	Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements (filed as Exhibit 12 to Form 10-K for the fiscal year ended December 31, 2001).
20*	--	Definitive Proxy Statement of Williams for 2002 (filed on Schedule 14A filed March 29, 2002).
21*	--	Subsidiaries of the registrant (filed as Exhibit 21 to Form 10-K for the fiscal year ended December 31, 2001).
23*	--	Consent of Independent Auditors, Ernst & Young LLP (filed as Exhibit 23 to Form 10-K for the fiscal year ended December 31, 2001).
24*	--	Power of Attorney together with certified resolution (filed as Exhibit 24 to Form 10-K for the fiscal year ended December 31, 2001).

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* Each such exhibit has heretofore been filed with the Securities and Exchange Commission as part of the filing indicated and is incorporated herein by reference.

** Williams agrees upon request to furnish each such exhibit to the Securities and Exchange Commission. The total amount of the securities authorized under each such exhibit does not exceed ten percent of the total assets of Williams and its subsidiaries taken as a whole.