WILLIAMS COMPANIES INC
Form 10-K/A
May 28, 2002

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	New York Stock Exchange and the
Preferred Stock Purchase Rights; and	Pacific Stock Exchange; and
Income PACS	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

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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 horse-

power 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.

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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

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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.