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

Form 10-K/A
(Amendment No. 1)

(Mark One)

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

For the fiscal year ended December 31, 2004

or

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 1-7176

El Paso CGP Company

(Exact Name of Registrant as Specified in Its Charter)

Delaware

(State or Other Jurisdiction of
Incorporation or Organization)

74-1734212

(I.R.S. Employer
Identification No.)

El Paso Building

1001 Louisiana Street

Houston, Texas

(Address of Principal Executive Offices)

77002

(Zip Code)

Telephone Number: (713) 420-2600

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

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 No

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

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant: None

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, par value \$1 per share. Shares outstanding on April 15, 2005: 1,000

EL PASO CGP COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTION I(1) (a) AND (b) TO FORM 10-K AND IS, THEREFORE, FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY SUCH INSTRUCTION.

Documents Incorporated by Reference: None

EL PASO CGP COMPANY
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* We have not included a response to this item in this document since no response is required pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Below is a list of terms that are common to our industry and used throughout this document:

/d = per day	Mgal = thousand gallons
Bbl = barrels	MMBtu = million British thermal units
BBtu = billion British thermal units	MMcf = million cubic feet
BBtue = billion British thermal unit equivalents	MMcfe = million cubic feet of natural gas equivalents
Bcf = billion cubic feet	MW = megawatt
Bcfe = billion cubic feet of natural gas equivalents	TBtu = trillion British thermal units
MBbls = thousand barrels	
Mcf = thousand cubic feet	
Mcfe = thousand cubic feet of natural gas equivalents	
MDth = thousand dekatherms	

When we refer to natural gas and oil in “equivalents,” we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to “us”, “we”, “our”, “ours”, “CGP” or “Coastal”, we are describing El Paso CGP Company and/or our subsidiaries.

EXPLANATORY NOTE

This Form 10-K/A (Amendment No. 1) is being filed to reflect adjustments in certain of our discontinued operations in 2003 and 2004, resulting from errors in the accounting and reporting for foreign currency translation adjustments (CTA) and related tax adjustments. There were no changes in income from continuing operations or total reported cash flows from operations for any period. We identified the accounting and reporting errors during the process of remediating the material weaknesses in internal control over financial reporting that we reported in our Form 10-K for the year ended December 31, 2004, as filed April 15, 2005.

Following a review of this matter, we determined that balances in CTA contained amounts related to businesses that had previously been sold or abandoned. These balances should have been reclassified to earnings upon the sale or abandonment of these entities. The adjustment of these CTA balances affected losses we recorded on several of these assets. In addition, we determined that upon initially recognizing U.S. deferred income taxes on our discontinued Canadian exploration and production operations, we did not properly allocate taxes to CTA.

In 2004, the income statement impact of these adjustments was a \$32 million reduction of our net loss from discontinued operations. In 2003, the impact of these adjustments was a reduction of our net loss from discontinued operations of \$35 million. As of December 31, 2004, the overall effect of these adjustments to total stockholders' equity was a decrease of \$1 million.

The restatement affects disclosures and tabular amounts in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations; Item 8. Financial Statements and Supplementary Data; and Item 9A. Controls and Procedures.

PART I

ITEM 1. BUSINESS

General

We are a Delaware corporation originally founded in 1955. In January 2001, we became a wholly owned subsidiary of El Paso Corporation (El Paso) through our merger with a wholly owned El Paso subsidiary.

Business Segments

For the year ended December 31, 2004, we had both regulated and non-regulated operations conducted through four business segments — Pipelines, Production, Power and Field Services. Through these segments, we provided the following energy related services:

Regulated Operations

Pipelines

We own or have interests in approximately 17,600 miles of pipeline and approximately 270 Bcf of storage capacity. We provide customers with interstate natural gas transmission and storage services from a diverse group of supply regions to major markets in the Midwest and western United States.

Non-regulated Operations

Production

We have interests in approximately 1.4 million net developed and undeveloped acres and had approximately 800 Bcfe of proved natural gas and oil reserves worldwide at the end of 2004. During 2004, our production averaged approximately 334 MMcfe/d.

Power

Our power business owns, manages or has an interest in approximately 3,700 MW of gross generating capacity in eight countries. Our plants serve customers under long-term and market-based contracts or sell to the open market in spot market transactions. We have completed the sale of substantially all of our domestic power operations and are evaluating potential opportunities to sell many of our remaining power assets.

Field Services

Our midstream or field services business provides processing and gathering services, primarily in south Louisiana. We currently expect to sell many of these assets.

During 2004, we also had discontinued operations related to a historical petroleum markets business and international natural gas and oil production operations, primarily in Canada.

Below is a discussion of each of our business segments. Our business segments provide a variety of energy products and services. We manage each segment separately and each segment requires different technology and marketing strategies. For additional discussion of our business segments, see Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. For our segment operating results and identifiable assets, see Part II, Item 8, Financial Statements and Supplementary Data, Note 15, which is incorporated herein by reference.

Regulated Business — Pipelines Segment

Our Pipelines segment provides natural gas transmission, storage and related services. We own or have interests in approximately 17,600 miles of interstate natural gas pipelines in the United States that connect the nation's principal natural gas supply regions to several large consuming regions in the United States. Our pipeline operations also include access to systems in Canada. We also own or have interests in approximately 270 Bcf of storage capacity used to provide a variety of flexible services to our customers.

Our Pipelines segment conducts its business activities primarily through four wholly owned and a partially owned interstate transmission system, along with four underground natural gas storage entities. The tables below detail our wholly owned and partially owned interstate transmission systems:

Wholly Owned Interstate Transmission Systems

Transmission System	Supply and Market Region	As of December 31, 2004			Average Throughput ⁽¹⁾		
		Miles of Pipeline	Design Capacity	Storage Capacity	2004	2003	2002
			(MMcf/d)	(Bcf)	(BBtu/d)		
ANR Pipeline (ANR)	Extends from Louisiana, Oklahoma, Texas and the Gulf of Mexico to the midwestern and northern regions of the U.S., including the metropolitan areas of Detroit, Chicago and Milwaukee.	10,500	6,620	192	4,067	4,232	4,130
Colorado Interstate Gas (CIG)	Extends from most production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and multiple interconnects with pipeline systems transporting gas to the Midwest, the Southwest, California and the Pacific Northwest.	4,000	3,000	29	1,744	1,685	1,687
Wyoming Interstate (WIC)	Extends from western Wyoming and the Powder River Basin to various pipeline interconnections near Cheyenne, Wyoming.	600	1,997	—	1,201	1,213	1,194
Cheyenne Plains Gas Pipeline (CPG)	Extends from the Cheyenne hub in Colorado to various pipeline interconnects near Greensburg, Kansas.	400	396 ⁽²⁾	—	89	—	—

⁽¹⁾ Includes throughput transported on behalf of affiliates.

⁽²⁾ This capacity was placed in service on December 1, 2004. Compression was added and placed in service on January 31, 2005, which increased the design capacity to 576 MMcf/d.

We also have several pipeline expansion projects underway as of December 31, 2004 that have been approved by the Federal Energy Regulatory Commission (FERC), the more significant of which are presented below:

Transmission System	Project	Capacity (MMcf/d)	Description	Anticipated Completion Date
ANR	EastLeg Wisconsin expansion	142	To replace 4.7 miles of an existing 14-inch natural gas pipeline with a 30-inch line in Washington County, add 3.5 miles of 8-inch looping ⁽¹⁾ on the Denmark Lateral in Brown County, and modify ANR's existing Mountain Compressor Station in Oconto County, Wisconsin.	November 2005
	NorthLeg Wisconsin expansion	110	To add 6,000 horsepower of electric powered compression at ANR's Weyauwega Compressor station in Waupaca County, Wisconsin.	November 2005
CPG	Cheyenne Plains expansion	179	To add approximately 10,300 horsepower of compression and an additional treatment facility to the Cheyenne Plains project.	December 2005

⁽¹⁾ Looping is the installation of a pipeline, parallel to an existing pipeline, with tie-ins at several points along the existing pipeline. Looping increases a transmission system's capacity.

Partially Owned Interstate Transmission System

Transmission System	Supply and Market Region	As of December 31, 2004			Average Throughput ⁽²⁾		
		Ownership Interest	Miles of Pipeline ⁽²⁾	Design Capacity ⁽²⁾	2004	2003	2002
		(Percent)		(MMcf/d)	(BBtu/d)		
Great Lakes Gas Transmission ⁽¹⁾	Extends from the Manitoba-Minnesota border to the Michigan-Ontario border at St. Clair, Michigan.	50	2,115	2,895	2,200	2,366	2,378

⁽¹⁾ This system is accounted for as an equity investment.

⁽²⁾ Miles, volumes and average throughput represent the system's totals and are not adjusted for our ownership interest.

We also have a 50 percent interest in Wyco Development, L.L.C. Wyco owns the Front Range Pipeline, a state-regulated gas pipeline extending from the Cheyenne Hub to Public Service Company of Colorado's (PSCo) Fort St. Vrain electric generation plant, and compression facilities on WIC's Medicine Bow Lateral. These facilities are leased to PSCo and WIC, respectively, under long-term leases.

Underground Natural Gas Storage Entities

In addition to the storage capacity on our transmission systems, we own or have interests in the following natural gas storage entities:

Storage Entity	As of December 31, 2004		Location
	Ownership Interest	Storage Capacity ⁽¹⁾	
	(Percent)	(Bcf)	
ANR Storage	100	56	Michigan
Blue Lake Gas Storage	75	47	Michigan
Eaton Rapids Gas Storage ⁽²⁾	50	13	Michigan
Young Gas Storage ⁽²⁾	48	6	Colorado

⁽¹⁾ Includes a total of 75 Bcf contracted to affiliates. Storage capacity is under long-term contracts and is not adjusted for our ownership interest.

⁽²⁾ These systems were accounted for as equity investments as of December 31, 2004.

Regulatory Environment

Our interstate natural gas transmission systems and storage operations are regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each of our pipeline systems and storage facilities operates under FERC-approved tariffs that establish rates, terms and conditions for services to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage and related services;
- certification and construction of new facilities;
- extension or abandonment of facilities;
- maintenance of accounts and records;
- relationships between pipeline and energy affiliates;
- terms and conditions of service;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

The fees or rates established under our tariffs are a function of our costs of providing services to our customers, including a reasonable return on our invested capital. Our revenues from transportation, storage and related services (transportation services revenues) consist of reservation revenues and usage revenues.

Reservation revenues are from customers (referred to as firm customers) whose contracts (which are for varying terms) reserve capacity on our pipeline systems or storage facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts. Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) who pay usage charges based on the volume of gas actually transported, stored, injected or withdrawn. In 2004, approximately 90 percent of our transportation service and storage revenues were attributable to reservation charges paid by firm customers. The remaining 10 percent of our revenues were variable. Due to our regulated nature and the high percentage of our revenues attributable to reservation charges, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as weather, changes in natural gas prices and market conditions, regulatory actions, competition and the creditworthiness of our customers. We also experience volatility in our financial results when the amount of gas utilized in our operations differs from the amounts we receive for that purpose.

Our interstate pipeline systems are also subject to federal, state and local pipeline safety and environmental statutes and regulations. Our systems have ongoing programs designed to keep our facilities in compliance with these safety and environmental requirements, and we believe that our systems are in material compliance with the applicable requirements.

Markets and Competition

We provide natural gas services to a variety of customers including natural gas producers, marketers, end-users and other natural gas transmission, distribution and electric generation companies. In performing these services, we compete with other pipeline service providers as well as alternative energy sources such as coal, nuclear and hydroelectric power for power generation and fuel oil for heating.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. Terminals and other regasification facilities can serve as important sources of supply for pipelines, enhancing the delivery capabilities and operational flexibility and complementing traditional supply transported into market areas. These LNG delivery systems also may compete with our pipelines for transportation of gas into market areas we serve.

Electric power generation is the fastest growing demand sector of the natural gas market. The growth and development of the electric power industry potentially benefits the natural gas industry by creating more demand for natural gas turbine generated electric power, but this effect is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity and increased natural gas prices. The increase in natural gas prices, driven in part by increased demand from the power sector, has diminished the demand for gas in the industrial sector. In addition, in several regions of the country, new additions in electric generating capacity have exceeded load growth and transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm contracts with pipelines and may impair their creditworthiness.

Our existing contracts mature at various times and in varying amounts of throughput capacity. As our pipeline contracts expire, our ability to extend our existing contracts or re-market expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or re-negotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although we, at times, and in certain regions, discount these rates to remain competitive. The level of discount varies for each of our pipeline systems.

The following table details the markets we serve and the competition faced by each of our wholly owned pipeline systems as of December 31, 2004:

Transmission System	Customer Information	Contract Information	Competition
ANR	<p>Approximately 259 firm and interruptible customers</p> <p>Major Customer: We Energies (909 BBtu/d)</p>	<p>Approximately 570 firm contracts Weighted average remaining contract term of approximately three years.</p> <p>Contract terms expire in 2005-2010.</p>	<p>In the Midwest, ANR competes with other interstate and intrastate pipeline companies and local distribution companies in the transportation and storage of natural gas. In the Northeast, ANR competes with other interstate pipelines serving electric generation and local distribution companies. ANR also competes directly with other interstate pipelines, including Guardian Pipeline, for markets in Wisconsin. We Energies owns an interest in Guardian, which is currently serving a portion of its firm transportation requirements.</p> <p>ANR also competes directly with numerous pipelines and gathering systems for access to new supply sources. ANR's principal supply sources are the Rockies and mid-continent production accessed in Kansas and Oklahoma, western Canadian production delivered to the Chicago area and Gulf of Mexico sources, including deepwater production and LNG imports.</p>
CIG	<p>Approximately 112 firm and interruptible customers</p> <p>Major Customer: Public Service Company of Colorado (970 BBtu/d) (261 BBtu/d) (187 BBtu/d)</p>	<p>Approximately 191 firm contracts Weighted average remaining contract term of approximately five years.</p> <p>Contract term expires in 2007. Contract term expires in 2009-2014. Contract terms expire in 2006.</p>	<p>CIG serves two major markets. Its "on-system" market consists of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming. Its "off-system" market consists of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the Midwest, the Southwest, California and the Pacific Northwest. Competition for its on-system market consists of local production from the Denver-Julesburg basin, an intrastate pipeline, and long-haul shippers who elect to sell into this market rather than the off-system market. Competition for its off-system market consists of other interstate pipelines that are directly connected to its supply sources.</p>

<u>Transmission System</u>	<u>Customer Information</u>	<u>Contract Information</u>	<u>Competition</u>
WIC	Approximately 49 firm and interruptible customers Major Customers: Williams Power Company (303 BBtu/d) Colorado Interstate Gas Company (247 BBtu/d) Western Gas Resources (235 BBtu/d) Cantera Gas Company (226 BBtu/d)	Approximately 47 firm contracts Weighted average remaining contract term of approximately six years. Contract terms expire in 2008-2013. Contract terms expire in 2005-2016. Contract terms expire in 2007-2013. Contract terms expire in 2012-2013.	WIC competes with eight interstate pipelines and one intrastate pipeline for its mainline supply from several producing basins. WIC's one Bcf/d Medicine Bow lateral is the primary source of transportation for increasing volumes of Powder River Basin supply and can readily be expanded as supply increases. Currently, there are two other interstate pipelines that transport limited volumes out of this basin.
CPG	Approximately 15 firm and interruptible customers. Major Customers: Oneok Energy Services Company L.P. (195 BBtu/d) Anadarko Energy Service Company (100 BBtu/d) Kerr McGee (83 BBtu/d)	Approximately 14 firm contracts Weighted average remaining contract term of approximately 10 years. Contract term expires in 2015. Contract term expires in 2015. Contract term expires in 2015.	Cheyenne Plains competes directly with other interstate pipelines serving the Mid-continent region. Indirectly, Cheyenne Plains competes with other interstate pipelines that transport Rocky Mountain gas to other markets.

Non-Regulated Business — Production Segment

Our Production segment is engaged in the exploration for, and the acquisition, development and production of natural gas, oil and natural gas liquids, in the United States and Brazil. In the United States, as of December 31, 2004, we controlled approximately one million net acres of leasehold acreage through our operations primarily in Texas, Utah, West Virginia and Wyoming, and through our offshore operations in federal and state waters in the Gulf of Mexico. During 2004, daily equivalent natural gas production averaged approximately 334 MMcfe/d, and our proved natural gas and oil reserves at December 31, 2004, were approximately 800 Bcfe.

We will focus on developing production opportunities around our asset base in the United States and in Brazil. Our other international operations that are not part of our long-term strategy have been treated as discontinued operations as further discussed in Part II, Item 8, Financial Statements and Supplementary Data, Note 2.

Our operations are divided into the following areas:

<u>Area</u>	<u>Operating Regions</u>
United States	
Onshore	Rocky Mountains (primarily in Utah)
Texas Gulf Coast	South Texas
Offshore	Gulf of Mexico (Texas and Louisiana)
Brazil	Camamu, Santos and Espirito Santo Basins

Natural Gas, Oil and Condensate and Natural Gas Liquids (NGL) Reserves

The tables below detail our proved reserves at December 31, 2004. Information in these tables is based on our internal reserve report. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 82 percent of our properties by volume. The total estimate of proved reserves prepared by Ryder Scott was within one percent of our internally prepared estimates presented in these tables. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. Ryder Scott was retained by and reports to the Audit Committee of El Paso's Board of Directors. The properties reviewed by Ryder Scott represented 84 percent of our proved properties based on value. Our estimated net proved reserves as of December 31, 2004, and our 2004 production are as follows:

	Net Proved Reserves ⁽¹⁾					2004 Production (MMcfe)
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe) (Percent)		
United States						
Onshore	35,260	12,749	—	111,758	14	5,860
Texas Gulf Coast	376,517	2,780	8,369	443,405	55	85,810
Offshore	99,757	3,830	230	124,122	15	30,426
Total United States	511,534	19,359	8,599	679,285	84	122,096
Brazil	—	20,795	—	124,772	16	—
Total	<u>511,534</u>	<u>40,154</u>	<u>8,599</u>	<u>804,057</u>	<u>100</u>	<u>122,096</u>

⁽¹⁾ Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

The table below summarizes our estimated net proved producing reserves, proved non-producing reserves, and proved undeveloped reserves as of December 31, 2004:

	Net Proved Reserves ⁽¹⁾				
	Natural Gas (MMcf)	Oil/Condensate (MBbls)	NGL (MBbls)	Total (MMcfe) (Percent)	
United States					
Producing	326,723	8,612	7,310	422,256	62
Non-Producing	92,197	5,360	374	126,603	19
Undeveloped	92,614	5,387	915	130,426	19
Total proved	<u>511,534</u>	<u>19,359</u>	<u>8,599</u>	<u>679,285</u>	<u>100</u>
Brazil — undeveloped	—	20,795	—	124,772	100
Worldwide					
Producing	326,723	8,612	7,310	422,256	52
Non-Producing	92,197	5,360	374	126,603	16
Undeveloped	92,614	26,182	915	255,198	32
Total proved	<u>511,534</u>	<u>40,154</u>	<u>8,599</u>	<u>804,057</u>	<u>100</u>

⁽¹⁾ Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of proved undeveloped reserves and proved non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves, projecting future rates of production and projecting the timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules prescribed by the SEC. These rules indicate that the standard of “reasonable certainty” be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

Acreege and Wells

The following table details our gross and net interest in developed and undeveloped acreage at December 31, 2004. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		Undeveloped		Total	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
United States						
Onshore	190,779	138,732	396,024	288,965	586,803	427,697
Texas Gulf Coast	115,876	76,193	220,806	163,236	336,682	239,429
Offshore	<u>296,879</u>	<u>196,640</u>	<u>95,437</u>	<u>86,961</u>	<u>392,316</u>	<u>283,601</u>
Total United States	603,534	411,565	712,267	539,162	1,315,801	950,727
Brazil	—	—	1,346,919	452,552	1,346,919	452,552
Total	<u>603,534</u>	<u>411,565</u>	<u>2,059,186</u>	<u>991,714</u>	<u>2,662,720</u>	<u>1,403,279</u>

⁽¹⁾ Gross interest reflects the total acreage we participated in, regardless of our ownership interests in the acreage.

⁽²⁾ Net interest is the aggregate of the fractional working interest that we have in our gross acreage.

Our United States net developed acreage is concentrated primarily in the Gulf of Mexico (48 percent), Utah (32 percent), and Texas (20 percent). Our United States net undeveloped acreage is concentrated primarily in Texas (31 percent), West Virginia (24 percent), Wyoming (20 percent), and the Gulf of Mexico (16 percent). Approximately 27 percent, 14 percent and 4 percent of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2005, 2006 and 2007.

The following table details our working interests in natural gas and oil wells in the United States at December 31, 2004:

	Productive Natural Gas Wells		Productive Oil Wells ⁽³⁾		Total Productive Wells		Number of Wells Being Drilled	
	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾	Gross ⁽¹⁾	Net ⁽²⁾
Onshore	35	6	287	217	322	223	—	—
Texas Gulf Coast	711	580	2	1	713	581	5	4
Offshore	155	120	34	27	189	147	2	—
Total	<u>901</u>	<u>706</u>	<u>323</u>	<u>245</u>	<u>1,224</u>	<u>951</u>	<u>7</u>	<u>4</u>

⁽¹⁾ Gross interest reflects the total number of wells we participated in, regardless of our ownership interests in the wells.

⁽²⁾ Net interest is the aggregate of the fractional working interest that we have in our gross wells.

⁽³⁾ Excludes two wells in Brazil that are not currently producing due primarily to regional infrastructure constraints.

We operated 922 of the 951 net productive wells as of December 31, 2004.

The following table details our exploratory and development wells drilled during the years 2002 through 2004:

	Net Exploratory Wells Drilled ⁽¹⁾			Net Development Wells Drilled ⁽¹⁾		
	2004	2003	2002	2004	2003	2002
United States						
Productive	12	19	18	10	53	166
Dry	<u>3</u>	<u>9</u>	<u>8</u>	<u>1</u>	<u>1</u>	<u>1</u>
Total	<u>15</u>	<u>28</u>	<u>26</u>	<u>11</u>	<u>54</u>	<u>167</u>
Brazil						
Productive	—	2	—	—	—	—
Dry	<u>1</u>	<u>4</u>	—	—	—	—
Total	<u>1</u>	<u>6</u>	—	—	—	—
Worldwide						
Productive	12	21	18	10	53	166
Dry	<u>4</u>	<u>13</u>	<u>8</u>	<u>1</u>	<u>1</u>	<u>1</u>
Total	<u>16</u>	<u>34</u>	<u>26</u>	<u>11</u>	<u>54</u>	<u>167</u>

⁽¹⁾ Net interest is the aggregate of the fractional working interest that we have in our gross wells drilled.

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of natural gas and oil that may ultimately be recovered.

Net Production, Sales Prices, Transportation and Production Costs

The following table details our net production volumes, average sales prices received, average transportation costs and average production costs associated with the sale of natural gas and oil for each of the three years ended December 31:

	2004	2003	2002
Net Production Volumes			
Natural gas (MMcf)	95,641	141,024	246,908
Oil, condensate and NGL (MBbls)	4,410	5,972	6,929
Total (MMcfe)	122,096	176,854	288,481
Natural Gas Average Realized Sales Price (\$/Mcf) ⁽¹⁾			

	<u>2004</u>	<u>2003</u>	<u>2002</u>
Price, excluding hedges	\$ 6.02	\$ 5.43	\$ 3.15
Price, including hedges ⁽²⁾	\$ 5.57	\$ 4.72	\$ 4.22
Oil, Condensate, and NGL Average Realized Sales Price (\$/Bbl) ⁽¹⁾			
Price, excluding hedges	\$ 35.24	\$ 25.25	\$ 20.08
Price, including hedges ⁽²⁾	\$ 35.24	\$ 25.25	\$ 20.12
Average Transportation Cost			
Natural gas (\$/Mcf)	\$ 0.11	\$ 0.15	\$ 0.15
Oil, condensate and NGL (\$/Bbl)	\$ 1.07	\$ 0.89	\$ 0.66
Average Production Cost (\$/Mcfe) ⁽³⁾			
Average lease operating cost	\$ 0.75	\$ 0.47	\$ 0.49
Average production taxes	0.12	0.17	0.08
Total production cost	<u>\$ 0.87</u>	<u>\$ 0.64</u>	<u>\$ 0.57</u>

⁽¹⁾ Prices are stated before transportation costs.

⁽²⁾ Our hedging activities are conducted with our affiliate, El Paso Marketing.

⁽³⁾ Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

Acquisition, Development and Exploration Expenditures

The following table details information regarding the costs incurred in our acquisition, development and exploration activities for each of the three years ended December 31:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	<u>(In millions)</u>		
United States			
Acquisition Costs:			
Proved	\$ 6	\$ —	\$ 23
Unproved	4	9	12
Development Costs	150	270	569
Exploration Costs:			
Delay Rentals	3	4	4
Seismic Acquisition and Reprocessing	—	1	2
Drilling	84	211	191
Asset Retirement Obligations ⁽¹⁾	11	77	—
Total full cost pool expenditures	<u>258</u>	<u>572</u>	<u>801</u>
Non-full cost pool expenditures	3	4	18
Total capital expenditures	<u>\$261</u>	<u>\$ 576</u>	<u>\$ 819</u>
Brazil			
Acquisition Costs:			
Unproved	\$ 3	\$ 4	\$ 9
Development Costs	1	—	—
Exploration Costs:			
Seismic Acquisition and Reprocessing	14	11	32
Drilling	10	84	13
Total full cost pool expenditures	<u>28</u>	<u>99</u>	<u>54</u>
Non-full cost pool expenditures	2	1	2
Total capital expenditures	<u>\$ 30</u>	<u>\$ 100</u>	<u>\$ 56</u>

	<u>2004</u>	<u>2003</u> (In millions)	<u>2002</u>
Worldwide			
Acquisition Costs:			
Proved	\$ 6	\$ —	\$ 23
Unproved	7	13	21
Development Costs	151	270	569
Exploration Costs:			
Delay Rentals	3	4	4
Seismic Acquisition and Reprocessing	14	12	34
Drilling	94	295	204
Asset Retirement Obligations ⁽¹⁾	11	77	—
Total full cost pool expenditures	286	671	855
Non-full cost pool expenditures	5	5	20
Total capital expenditures	<u>\$291</u>	<u>\$ 676</u>	<u>\$ 875</u>

⁽¹⁾ Includes an increase to our property, plant and equipment of approximately \$71 million in 2003 associated with our adoption of Statement of Financial Accounting Standards No. 143.

We spent approximately \$11 million in 2004, \$50 million in 2003 and \$88 million in 2002 to develop proved undeveloped reserves that were included in our reserve report as of January 1 of each year.

Regulatory and Operating Environment

Our natural gas and oil activities are regulated at the federal, state and local levels, as well as internationally by the countries in which we do business. These regulations include, but are not limited to, the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to governmental safety regulations in the jurisdictions in which we operate.

Our domestic operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the Minerals Management Service, which has promulgated valuation guidelines for the payment of royalties by producers. Our international operations are subject to environmental regulations administered by foreign governments, which include political subdivisions and international organizations. These domestic and international laws and regulations relating to the protection of the environment affect our natural gas and oil operations through their effect on the construction and operation of facilities, water disposal rights, drilling operations, production or the delay or prevention of future offshore lease sales. We believe that our operations are in material compliance with the applicable requirements. In addition, El Paso maintains insurance on our behalf to limit exposure to potential losses from sudden and accidental spills and oil pollution liability.

Our production business has operating risks normally associated with the exploration for and production of natural gas and oil, including blowouts, cratering, pollution and fires, each of which could result in damage to property or injuries to people. Offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, damage from collisions with vessels, governmental regulations and interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, El Paso maintains insurance coverage on our behalf to limit exposure to potential losses resulting from these operating hazards.

Markets and Competition

We primarily sell our natural gas and oil to third parties through our affiliates at spot market prices, subject to customary adjustments. We sell our natural gas liquids at market prices under monthly or long-term contracts, subject to customary adjustments. We also engage in hedging activities with El Paso Marketing on a portion of our natural gas and oil production to stabilize our cash flows and reduce the risk of downward commodity price movements on sales of our production.

The natural gas and oil business is highly competitive in the search for and acquisition of additional reserves and in the sale of natural gas, oil and natural gas liquids. Our competitors include major and

intermediate sized natural gas and oil companies, independent natural gas and oil operations and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price, contract terms and our ability to access drilling and other equipment on a timely and cost effective basis. Ultimately, our future success in the production business will be dependent on our ability to find or acquire additional reserves at costs that allow us to remain competitive.

Non-regulated Business — Power Segment

Our Power segment includes the ownership and operation of international and domestic power generation facilities as well as the management of restructured power contracts. As of December 31, 2004, we owned or had interests in 17 power facilities in eight countries with a total generating capacity of approximately 3,700 gross MW. Our commercial focus has historically been either to develop projects in which new long-term power purchase agreements allow for an acceptable return on capital, or to acquire projects with existing above-market power purchase agreements. However, during 2004 and through the first quarter of 2005, we sold substantially all of our domestic power operations. We will continue to evaluate potential opportunities to sell or otherwise divest many of our remaining power assets.

International Power. As of December 31, 2004, we owned or had a direct investment in the following international power plants:

<u>Project</u>	<u>Country</u>	<u>Ownership Interest⁽¹⁾ (Percent)</u>	<u>Gross Capacity (MW)</u>	<u>Power Purchaser</u>	<u>Expiration Year of Power Sales Contracts</u>	<u>Fuel Type</u>
<i>Asia</i>						
Habibullah	Pakistan	50	136	Pakistan Water and Power	2029	Natural Gas
Khulna	Bangladesh	74	113	Bangladesh Power	2013	Oil
Nanjing	China	80	75	Jiangsu Power	2017	Diesel
Saba	Pakistan	94	128	Pakistan Water and Power	2029	Oil
Suzhou	China	60	109	Jiangsu Power	2016	Natural Gas
Wuxi	China	60	39	Jiangsu Power	2010	Natural Gas
<i>Central America</i>						
CEPP	Dominican Republic	48	67	CDEEE, Spot Market	2014	Oil
Fortuna	Panama	25	300	Union Fenosa	2005, 2008	Hydroelectric
GEOSA	Nicaragua	26	115	Union Fenosa, Spot Market	2005, 2008	Oil
Itabo	Dominican Republic	25	416	CDEEE and AES	2016	Oil/Coal
Nejapa ⁽¹⁾	El Salvador	87	144	AES and PPL	2005	Oil
Pedregal	Panama	21	50	Union Fenosa	2005	Oil
Tipitapa	Nicaragua	60	51	Union Fenosa	2014	Oil

⁽¹⁾ Our Nejapa power facility is consolidated in our financial statements. Our interests in all other international power facilities are reflected as investments in unconsolidated affiliates in our financial statements.

Domestic Power Plants. During 2004 and the first quarter of 2005, we sold substantially all of our domestic power assets. As of December 31, 2004, we owned or had a direct investment in the following domestic power facilities:

<u>Project</u>	<u>State</u>	<u>El Paso Ownership Interest (Percent)</u>	<u>Gross Capacity (MW)</u>	<u>Power Purchaser</u>	<u>Expiration Year of Power Sales Contracts</u>	<u>Fuel Type</u>
Midland Cogeneration ⁽¹⁾	MI	44	1,575	Consumers Power, Dow	2025	Natural Gas
CDECCA ⁽³⁾	CT	50	62	— ⁽²⁾	— ⁽²⁾	Natural Gas
Eagle Point ⁽⁴⁾	NJ	84	233	— ⁽²⁾	— ⁽²⁾	Natural Gas
Rensselaer ⁽⁴⁾	NY	100	86	— ⁽²⁾	— ⁽²⁾	Natural Gas

⁽¹⁾ This power facility is reflected as an investment in unconsolidated affiliates in our financial statements.

⁽²⁾ These power facilities (referred to as merchant plants) do not have long-term power purchase agreements with third parties. El Paso Marketing sells the power that a majority of these facilities generate to the wholesale power market.

⁽³⁾ This plant has Board approval for sale and is targeted to be sold in the first half of 2005.

⁽⁴⁾ These plants were sold in the first quarter of 2005.

Regulatory Environment & Markets and Competition

International. Our international power generation activities are regulated by numerous governmental agencies in the countries in which these projects are located. Many of these countries have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures are subject to change (including differing interpretations) over time.

Many of our international power generation facilities sell power under long-term power purchase agreements primarily with power transmission and distribution companies owned by the local governments where the facilities are located. When these long-term contracts expire, these facilities will be subject to regional market, competitive and political risks.

Domestic. Our domestic power generation activities are regulated by the FERC under the Federal Power Act with respect to the rates, terms and conditions of service of these regulated plants. Our cogeneration power production activities are regulated by the FERC under the Public Utility Regulatory Policies Act of 1987 with respect to rates, procurement and provision of services and operating standards. Our power generation activities are also subject to federal, state and local environmental regulations.

Non-regulated Business — Field Services Segment

Our Field Services segment conducts our midstream activities, which include gathering and processing of natural gas for natural gas producers, primarily in the south Louisiana production area. We currently expect to sell many of these assets.

Gathering and Processing Assets. As of December 31, 2004, our gathering systems consisted of 77 miles of pipeline with 25 MMcfe/d of throughput capacity. These systems had average throughput of 7 BBtue/d during 2004. Our processing facilities had operational capacity and volumes as follows:

<u>Processing Plants</u>	<u>Inlet Capacity</u>	<u>Average Inlet Volume</u>			<u>Average Sales</u>		
	<u>December 31, 2004</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(MMcfe/d)	(BBtue/d)			(Mgal/d)		
South Louisiana	2,550	1,600	1,627	1,407	1,631	1,726	1,604
Other areas	49	18	60	347	38	139	739
Total	<u>2,599</u>	<u>1,618</u>	<u>1,687</u>	<u>1,754</u>	<u>1,669</u>	<u>1,865</u>	<u>2,343</u>

Regulatory Environment. Some of our operations, owned directly or through equity investments, are subject to regulation by the Railroad Commission of Texas under the Texas Utilities Code and the Common Purchaser Act of the Texas Natural Resources Code. Field Services files the appropriate rate tariffs and operates under the applicable rules and regulations of the Railroad Commission.

In addition, some of our operations, owned directly or through equity investments, are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act of 1979 and various environmental statutes and regulations. Each of our pipelines has continuing programs designed to keep the facilities in compliance with pipeline safety and environmental requirements, and we believe that these systems are in material compliance with the applicable requirements.

Markets and Competition. We compete with major interstate and intrastate pipeline companies in transporting natural gas and NGL. We also compete with major integrated energy companies, independent natural gas gathering and processing companies, natural gas marketers and oil and natural gas producers in gathering and processing natural gas and NGL. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling and production activity, customer service and access to favorable downstream markets.

Other Operations and Assets

We currently have a number of other assets and businesses that are either included as part of our corporate activities or as discontinued operations.

Corporate Activities

Our corporate operations include our general and administrative functions as well as our petroleum ship charter operations and various other contracts and assets, all of which were insignificant to our results in 2004.

Discontinued Operations

Our discontinued operations consist of our petroleum markets business and our international natural gas and oil production operations, primarily in Canada.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 13, and is incorporated herein by reference.

Employees

As of April 5, 2005, we had approximately 900 full-time employees, none of whom are subject to collective bargaining agreements.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

Details of the cases listed below, as well as a description of our legal proceedings are included in Part II, Item 8, Financial Statements and Supplementary Data, Note 13, and is incorporated herein by reference.

Corpus Christi Refinery Air Violations. On March 18, 2004, the Texas Commission on Environmental Quality issued an “Executive Director’s Preliminary Report and Petition” seeking \$645,477 in penalties relating to air violations alleged to have occurred at our former Corpus Christi, Texas refinery from 1996 to 2000. We filed a hearing request to protect our procedural rights. Pursuant to discussions on March 16, 2005, the parties have reached an agreement in principle to resolve the allegations for \$272,097. The parties are drafting the final settlement document formalizing the agreement.

Coastal Eagle Point Air Issues. Pursuant to the Environmental Protection Agency’s (EPA) Petroleum Refinery Initiative, our former Eagle Point refinery resolved certain claims of the U.S. and the State of New Jersey in a Consent Decree entered in December 2003. The Eagle Point refinery will invest an estimated \$3 million to \$7 million to upgrade the plant’s environmental controls by 2008. The Eagle Point Refinery was sold in January 2004. We will share certain future costs associated with implementation of the Consent Decree pursuant to the Purchase and Sale Agreement. On April 1, 2004, the New Jersey Department of Environmental Protection issued an Administrative Order and Notice of Civil Administrative Penalty Assessment seeking \$183,000 in penalties for excess emission events that occurred during the fourth quarter of 2003, prior to the sale. We have filed an administrative appeal contesting the penalty.

St. Helens. On November 11, 2003, our St. Helens, Oregon chemical plant discovered a release of ammonia at the facility and reported the release to the National Response Center and state and local contacts on November 12, 2003. On December 3, 2003, the St. Helens plant was sold to Dyno Nobel, Inc. On April 21, 2004, the EPA issued a demand to El Paso Merchant Energy — Petroleum Company for penalties for alleged reporting violations. We responded to the EPA’s demand, and we have fully resolved the alleged violations by paying a penalty of \$50,345 and conducting a supplemental project costing \$59,581.

Natural Buttes. In May 2004, we met with the EPA to discuss potential “prevention of significant deterioration” violations due to a de-bottlenecking modification at Colorado Interstate Gas Company’s facility. The EPA issued an Administrative Compliance Order. We are in negotiations with the EPA as to the appropriate penalty and have reserved our anticipated settlement amount.

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

None.

PART II

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

All of our common stock, par value \$1 per share, is owned by El Paso and, accordingly, our common stock is not publicly traded.

ITEM 6. SELECTED FINANCIAL DATA

Item 6, Selected Financial Data, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

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

The information required by this Item is presented in a reduced disclosure format permitted by General Instruction I to Form 10-K. The Notes to Consolidated Financial Statements contain information that is pertinent to the following analysis, including a discussion of our significant accounting policies. Certain historical financial information in this section has been restated, as further described in Item 8, Financial Statements and Supplementary Data, Note 1.

Liquidity and Capital Resources

El Paso is a significant source of liquidity to us and we participate in its cash management program. Under this program, depending on whether we have short-term cash surpluses or requirements, we either provide cash to El Paso or El Paso provides cash to us. We have historically and consistently borrowed cash from El Paso under this program.

Some of our subsidiaries are subsidiary guarantors of El Paso's \$3 billion credit agreement. In connection with these guarantees, El Paso pledged our ownership of ANR, ANR Storage, CIG, and WIC to collateralize the \$3 billion credit agreement. Our ownership in the above mentioned companies is subject to change if there is an event of default under the \$3 billion credit agreement and the lenders under the \$3 billion credit agreement exercise their rights over the collateral. If this were to occur, it could have a material adverse effect on our financial condition. In addition, one of our subsidiaries has pledged as collateral a portion of its natural gas and oil properties to support the obligations of some of our affiliates to make payments in connection with the settlement of various lawsuits arising out of the Western Energy Crisis. If our affiliates fail to make those payments, the properties that our subsidiary has pledged could be subject to foreclosure, which could have a material adverse effect on our financial position, results of operations and cash flows.

We have cross-acceleration provisions in some of our long-term debt-agreements which, if triggered, could result in the acceleration of our debt. The most restrictive indenture has a cross-acceleration threshold of \$5 million. The acceleration of our long-term debt could adversely affect our liquidity position and, in turn, our financial condition.

For a further discussion of our debt, other obligations and other commitments and obligations, see Item 8, Financial Statements and Supplementary Data, Notes 12 and 13.

Results of Operations

Overview

As of December 31, 2004, our operating business segments were Pipelines, Production, Power and Field Services. These segments provide a variety of energy products and services. They are managed separately and each requires different technology and marketing strategies. Our businesses are divided into two primary business lines: regulated and non-regulated. Our regulated business includes our Pipelines segment, while our non-regulated business includes our Production, Power and Field Services segments.

Our management, as well as El Paso's management, uses EBIT to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our businesses consist of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results independently from our financing methods or capital structure. We believe EBIT is helpful to our investors because it allows them to more effectively evaluate the operating performance of both our consolidated businesses and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be

considered in conjunction with net income and other performance measures such as operating income or operating cash flow.

Below is a reconciliation of our EBIT (by segment) to our consolidated net loss for each of the years ended December 31:

	<u>2004</u> <u>(Restated)⁽¹⁾</u>	<u>2003</u> <u>(Restated)⁽¹⁾</u>
	(In millions)	
<i>Regulated Business</i>		
Pipelines	\$ 434	\$ 500
<i>Non-regulated Businesses</i>		
Production	171	219
Power	(349)	39
Field Services	<u>55</u>	<u>(52)</u>
Segment EBIT	311	706
Corporate	<u>1</u>	<u>1</u>
Consolidated EBIT	312	707
Interest and debt expense	(341)	(407)
Affiliated interest expense, net	—	(41)
Distributions on preferred interests of consolidated subsidiaries	—	(17)
Income taxes	<u>(12)</u>	<u>(43)</u>
Income (loss) from continuing operations	(41)	199
Discontinued operations, net of income taxes	(115)	(1,286)
Cumulative effect of accounting changes, net of income taxes	<u>—</u>	<u>(12)</u>
Net loss	<u>\$ (156)</u>	<u>\$ (1,099)</u>

⁽¹⁾ See Part II, Item 8, Financial Statements and Supplementary Data, Note 1 for a discussion of the restatements of our 2004 and 2003 financial statements. The restatement of our 2004 financial statements affected the amount of losses in, and recorded on, our discontinued operations. The restatement of our 2003 financial statements affected the amount of income taxes recorded in discontinued operations related to our Canadian exploration and production operations.

Individual Segment Results

Regulated Business — Pipelines Segment

Our Pipelines segment consists of interstate natural gas transmission, storage and related services in the United States. We face varying degrees of competition in this segment from other pipelines and proposed LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, nuclear, coal and fuel oil.

The FERC regulates the rates we can charge our customers. These rates are a function of the cost of providing services to our customers, including a reasonable return on our invested capital. As a result, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices and market conditions, regulatory actions, competition, the creditworthiness of our customers and weather. In 2004, approximately 90 percent of our transportation service and storage revenues were attributable to reservation charges paid by firm customers. The remaining 10 percent of our revenues were variable. We also experience earnings volatility when the amount of natural gas utilized in operations differs from the amounts we receive for that purpose.

Historically, much of our business was conducted through long term contracts with customers. However, over the past several years some of our customers have shifted from a traditional dependence solely on long-

term contracts to a portfolio approach which balances short-term opportunities with long-term commitments. This shift, which can increase the volatility of our revenues, is due to changes in market conditions and competition driven by state utility deregulation, local distribution company mergers, new supply sources, volatility in natural gas prices, demand for short-term capacity and new power plant markets.

In addition, our ability to extend existing customer contracts or re-market expiring contracted capacity is dependent on the competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory constraints, we attempt to re-contract or re-market our capacity at the maximum rates allowed under our tariffs, although, at times, we discount these rates to remain competitive. The level of discount varies for each of our pipeline systems. Our existing contracts mature at various times and in varying amounts of throughput capacity. We continue to manage our recontracting process to limit the risk of significant impacts on our revenues. The weighted average remaining contract term for active contracts is approximately 4 years as of December 31, 2004. Below is the expiration schedule for contracts executed as of December 31, 2004, including those whose terms begin in 2005 or later.

	<u>MDth/d</u>	<u>Percent of Total Contracted Capacity</u>
2005	1,912	14
2006	2,581	19
2007	2,133	16
2008 and beyond	7,016	51

Operating Results

Below are the operating results and analysis of these results for our Pipelines segment for each of the years ended December 31:

<u>Pipelines Segment Results</u>	<u>2004</u>	<u>2003</u>
	<u>(In millions, except volume amounts)</u>	
Operating revenues	\$ 858	\$ 918
Operating expenses	(508)	(521)
Operating income	350	397
Other income	84	103
EBIT	<u>\$ 434</u>	<u>\$ 500</u>
Throughput volumes (BBtu/d) ⁽¹⁾	<u>7,962</u>	<u>8,158</u>

⁽¹⁾ Throughput volumes exclude intrasegment activities.

The following contributed to our overall EBIT decrease in 2004 as compared to 2003:

	<u>Revenue</u>	<u>Expense</u>	<u>Other</u>	<u>EBIT Impact</u>
	Favorable/(Unfavorable)			
	(In millions)			
Contract modifications/terminations	\$(68)	\$ 37	\$ —	\$(31)
Gas not used in operations, processing revenues and other natural gas sales	26	(14)	—	12
Other regulatory matters	—	(9)	(19)	(28)
Equity earnings from Great Lakes	—	—	8	8
Other ⁽¹⁾	<u>(18)</u>	<u>(1)</u>	<u>(8)</u>	<u>(27)</u>
Total impact on EBIT	<u><u>\$(60)</u></u>	<u><u>\$ 13</u></u>	<u><u>\$(19)</u></u>	<u><u>\$(66)</u></u>

⁽¹⁾ Consists of individually insignificant items across several of our pipeline systems.

The following provides further discussion on the items listed above as well as an outlook on events that may affect our operations in the future.

Contract Modifications/Terminations. Included in this item are (i) the renegotiation or restructuring of several contracts on our pipeline systems, including ANR's contracts with We Energies which contributed to the decrease in revenues by \$36 million in 2004 and (ii) the termination of the Dakota gasification facility contract on ANR's system, which resulted in lower operating revenues and lower operating expenses during 2004, without a significant overall impact on operating income and EBIT.

Guardian Pipeline, which is owned in part by We Energies, currently provides a portion of We Energies' firm transportation requirements and, therefore, directly competes with ANR for a portion of the markets in Wisconsin. This could impact ANR's existing customer contracts as well as future contractual negotiations with We Energies. In addition, ANR has entered into an agreement with a shipper to restructure one of its transportation contracts on its Southeast Leg as well as a related gathering contract. In March 2005, this restructuring was completed and ANR received approximately \$26 million, which will be included in its earnings during the first quarter of 2005.

Gas not used in Operations, Processing Revenues and Other Gas Sales. The financial impact of operational gas, net of gas used in operations is based on the amount of natural gas we are allowed to recover and dispose of according to our tariff, relative to the amounts of gas we use for operating purposes, and the price of natural gas. Gas not needed for operations results in revenues to us, which is driven by volumes and prices during the period. During 2004, we recovered, fairly consistently, volumes of natural gas that were not utilized for operations. These recoveries were and are based on factors such as system throughput, facility enhancements, gas processing margins and the ability to operate the systems in the most efficient and safe manner. Additionally, a steadily increasing natural gas price environment during this timeframe also resulted in favorable impacts on our operating results in 2004 versus 2003. We anticipate that this area of our business will continue to vary in the future and will be impacted by things such as rate actions, efficiency of our pipeline operations, natural gas prices and other factors.

Expansions. During the two years ended December 31, 2004, we completed a number of expansion projects that have generated or will generate new sources of revenues, the more significant of which was our ANR WestLeg Expansion. Our expansions during these years added approximately 310 MMcf/d to our overall pipeline system.

Our pipeline systems connect the principal gas supply regions to the largest consuming regions in the U.S. We are well-positioned to capture growth opportunities in the Rocky Mountains and deepwater Gulf of Mexico, and have an infrastructure that complements LNG growth. We are aggressively seeking to attach new supplies of natural gas to our systems in order to maintain an adequate supply of gas to serve our growing markets and to replace quantities lost due to the natural decline in production from wells currently attached to our system.

Expansion projects currently in process include:

Rocky Mountain expansions. In order to provide an outlet for the growing supply of Rocky Mountain natural gas to markets in the Midwest region of the United States, we have several expansion projects that will increase our transportation capacity, subject to regulatory approval, as follows:

- Cheyenne Plains Gas Pipeline commenced free-flow operations in December 2004 and as of January 31, 2005 is fully in-service. Approval has already been received for Cheyenne Plains Phase II which will add an additional 179 MMcf/d of capacity that is scheduled to be available by the end of 2005.
- CIG's Raton Basin 2005 Expansion will add 104 MMcf/d of capacity that is scheduled to be available by the end of 2005.
- WIC expects to complete its Piceance lateral with capacity of 333 MMcf/d by the end of 2005.

Other expansions. On our ANR system we continue to experience intense competition along its mainline corridors; however, it is well-positioned to provide transportation service from discoveries in the deepwater Gulf of Mexico and LNG supply growth along the Gulf Coast. These new supplies are expected to offset the continued decline of production from the Gulf of Mexico shelf. Additionally, ANR is proceeding with its Eastleg and Northleg expansions in its Wisconsin market area.

Other Regulatory Matters. In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately \$6 million to \$12 million annually over the next eight years.

In 2003 we re-applied Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, on our CIG and WIC systems, resulting in income from recording the regulatory assets of these systems. SFAS No. 71 allows a company to capitalize items that will be considered in future rate proceedings and \$18 million in income resulted from the capitalization of those items that we believe will be considered in CIG's and WIC's future rate cases. At the same time CIG and WIC re-applied SFAS No. 71, they adopted the FERC depreciation rate for their regulated plant and equipment. This change resulted in an increase in depreciation expense of approximately \$9 million in 2004, an increase which will continue in the future. As of December 31, 2004, ANR Storage Company re-applied SFAS No. 71 which had an immaterial impact and also adopted the FERC depreciation rate which will result in future depreciation expense increases of approximately \$4 million annually.

Our pipeline systems periodically file for changes in their rates which are subject to the approval of the FERC. Changes in rates and other tariff provisions resulting from these regulatory proceedings have the potential to negatively impact our profitability. CIG is required to file for new rates that would be effective October 2006. Our other pipelines have no requirements to file new rate cases and, absent any further regulatory action, expect to continue operating under their existing rates.

Non-regulated Businesses — Production Segment

Our Production segment conducts our natural gas and oil exploration and production activities. Our operating results are driven by a variety of factors including the ability to locate and develop economic natural gas and oil reserves, extract those reserves with minimal production costs, sell the products at attractive prices and minimize our total administrative costs.

Our long-term strategy includes developing our production opportunities primarily in the United States and Brazil, while prudently divesting of production properties outside of these regions. We emphasize strict capital discipline designed to improve capital efficiencies through the use of standardized risk analysis and a heightened focus on cost control. We also implemented a more rigorous process for booking proved natural gas and oil reserves, which includes multiple layers of reviews by personnel independent of the reserve estimation process. Our plan is to stabilize production by improving the production mix across our operating areas and to generate more predictable returns. We intend to improve our production mix by allocating more capital to long-life, slower decline projects and to develop projects in longer reserve life areas. This is being accomplished through our more rigorous capital review process and a more balanced allocation of our capital to development and exploration projects, supplemented by acquisition activities with low-risk development locations that provide operating synergies with our existing operations. In March 2005, we purchased the interests held by one of the parties under a net profits interest agreement for approximately \$22 million. See Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations for a further discussion of our net profits interest agreements.

Reserves, Production and Costs

Our estimate of proved natural gas and oil reserves as of December 31, 2004, reflects 679 Bcfe of proved reserves in the United States and 125 Bcfe of proved reserves in Brazil. These estimates were prepared internally by us. Ryder Scott Company, an independent petroleum engineering firm, prepared an estimate of our natural gas and oil reserves for 82 percent of our properties by volume. The total estimate of proved reserves prepared by Ryder Scott is within one percent of our internally prepared estimates. Ryder Scott was retained by and reports to the Audit Committee of El Paso's Board of Directors. The properties reviewed by Ryder Scott represented 84 percent of our properties based on value. For additional information on our estimated proved reserves and the processes by which they are developed, see Part I, Item 1, Business, Non-regulated Business — Production Segment, Item 7, Risk Factors, and Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Natural Gas and Oil Operations.

For 2004, our total equivalent production declined 55 Bcfe or 31 percent as compared to 2003. The decrease was due to production declines in our Texas Gulf Coast and offshore Gulf of Mexico regions and a significantly reduced capital expenditure program in 2004 compared to 2003.

Our depletion rate is determined under the full cost method of accounting. Due to disappointing drilling performance in 2004 that resulted in higher finding and development costs, we expect our domestic unit of production depletion rate to increase from \$2.68/Mcfe in the fourth quarter of 2004 to \$2.73/Mcfe in the first quarter of 2005. Our future trends in production and depletion rates will be dependent upon the amount of capital allocated to our Production segment, the level of success in our drilling programs and any future sale or acquisition activities relating to our proved reserves.

Our relatively high historical finding and development costs and disappointing drilling performance increase the likelihood of future ceiling test charges if natural gas and oil prices decline or if we experience negative reserve revisions.

Production Hedge Position

As part of our overall strategy, we hedge our natural gas and oil production to stabilize cash flows, reduce the risk of downward commodity price movements on our sales and to protect the economic assumptions associated with our capital investment programs. We conduct our hedging activities through natural gas and oil derivatives on our natural gas and oil production. Because this hedging strategy only partially reduces our exposure to downward movements in commodity prices, our reported results of operations, financial position and cash flows can be impacted significantly by movements in commodity prices from period to period. At December 31, 2004, our hedging position included 12,750 BBtu of our anticipated natural gas production for each quarter in 2005 at a hedged price of \$3.31 per MMBtu.

In December 2004, we replaced our existing hedges on approximately 51 TBtu of natural gas with new hedge transactions at the same volume and over the same time period. The combination of our original hedges

and the new transactions will not change the average price at which we are hedged and will not have an impact on our realized prices. As a result, these transactions will have the same impact on our accumulated other comprehensive income balances, cash flow and income statements as our original derivative positions that existed prior to December 1, 2004. However, these transactions “locked in” a loss of approximately \$180 million in accumulated other comprehensive income that will be recognized in earnings as our original hedged transactions settle in 2005. We have entered into a service agreement with El Paso that provides for a reimbursement of 2.5 cents per MMBtu in 2005 for our expected administrative costs associated with these transactions.

Operational Factors Affecting the Year Ended December 31, 2004

During 2004, our Production segment experienced the following:

- *Higher realized prices.* Realized natural gas prices, which include the impact of our hedges, increased 18 percent and oil, condensate and NGL prices increased 40 percent compared to 2003.
- *Average daily production.* During 2004, our average daily production was 334 MMcfe/d (excluding discontinued Canadian and other international operations of 15 MMcfe/d).
- *Capital expenditures of \$291 million (excluding discontinued Canadian and other international expenditures of \$29 million).* During the first quarter of 2004, we experienced disappointing drilling results. As a result, we significantly reduced our drilling activities and instituted a new, more rigorous, risk analysis program, with an emphasis on strict capital discipline. During 2004, we drilled 27 wells with an 81 percent success rate.
- *Sale of Canadian and other international operations.* These operations were sold in order to focus our operations in the United States and Brazil.

Operating Results

Below are our Production segment’s operating results and analysis of these results for each of the years ended December 31:

<u>Production Segment Results</u>	<u>2004</u>	<u>2003</u>
	(In millions)	
Operating revenues:		
Natural gas	\$ 533	\$ 666
Oil, condensate and NGL	155	151
Other	<u>2</u>	<u>5</u>
Total operating revenues	690	822
Transportation and net product costs	<u>(15)</u>	<u>(30)</u>
Total operating margin	<u>675</u>	<u>792</u>
Depreciation, depletion and amortization	(315)	(347)
Production costs ⁽¹⁾	(107)	(114)
Ceiling test and other charges ⁽²⁾	—	(44)
General and administrative expenses	(80)	(80)
Taxes, other than production and income taxes	<u>1</u>	<u>—</u>
Total operating expenses ⁽³⁾	<u>(501)</u>	<u>(585)</u>
Operating income	174	207
Other income (expense)	<u>(3)</u>	<u>12</u>
EBIT	<u>\$ 171</u>	<u>\$ 219</u>

	<u>2004</u>	<u>Percent Variance</u>	<u>2003</u>
Volumes, prices and cost per unit:			
Natural gas			
Volumes (MMcf)	<u>95,641</u>	(32)%	<u>141,024</u>
Average realized prices including hedges (\$/Mcf) ⁽⁴⁾ ...	<u>\$ 5.57</u>	18%	<u>\$ 4.72</u>
Average realized prices excluding hedges (\$/Mcf) ⁽⁴⁾ ...	<u>\$ 6.02</u>	11%	<u>\$ 5.43</u>
Average transportation costs (\$/Mcf)	<u>\$ 0.11</u>	(27)%	<u>\$ 0.15</u>
Oil, condensate and NGL			
Volumes (MBbls)	<u>4,410</u>	(26)%	<u>5,972</u>
Average realized prices including hedges (\$/Bbl) ⁽⁴⁾ ...	<u>\$ 35.24</u>	40%	<u>\$ 25.25</u>
Average realized prices excluding hedges (\$/Bbl) ⁽⁴⁾ ...	<u>\$ 35.24</u>	40%	<u>\$ 25.25</u>
Average transportation costs (\$/Bbl)	<u>\$ 1.07</u>	20%	<u>\$ 0.89</u>
Total equivalent volumes (MMcfe)	<u>122,096</u>	(31)%	<u>176,854</u>
Production cost (\$/Mcfe)			
Average lease operating cost	<u>\$ 0.75</u>	60%	<u>\$ 0.47</u>
Average production taxes	<u>0.12</u>	(29)%	<u>0.17</u>
Total production cost ⁽¹⁾	<u>\$ 0.87</u>	36%	<u>\$ 0.64</u>
Average general and administrative expenses (\$/Mcfe)	<u>\$ 0.65</u>	44%	<u>\$ 0.45</u>
Unit of production depletion cost (\$/Mcfe)	<u>\$ 2.42</u>	32%	<u>\$ 1.84</u>

(1) Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

(2) Includes ceiling test charges, asset impairments and gains on asset sales.

(3) Transportation costs are included in operating expenses on our consolidated statements of income.

(4) Prices are stated before transportation costs.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Our EBIT for 2004 decreased \$48 million as compared to 2003. Despite an 18 percent increase in natural gas prices including hedges, we experienced a significant decrease in operating revenues due to lower production volumes as a result of production declines, asset sales, a lower capital spending program and disappointing drilling results. The table below lists the significant variances in our operating results in 2004 as compared to 2003:

	Variance		
	Operating Revenue	Operating Expense	EBIT Impact
	Favorable/(Unfavorable) (In millions)		
<i>Natural Gas Revenue</i>			
Higher prices in 2004.....	\$ 56	\$ —	\$ 56
Lower production volumes in 2004	(247)	—	(247)
Impact from hedge program in 2004 versus 2003	58	—	58
<i>Oil, Condensate, and NGL Revenue</i>			
Higher realized prices in 2004	44	—	44
Lower production volumes in 2004	(40)	—	(40)
<i>Depreciation, Depletion, and Amortization Expense</i>			
Higher depletion rate in 2004	—	(71)	(71)
Lower production volumes in 2004	—	101	101
<i>Production Costs</i>			
Higher lease operating costs in 2004	—	(9)	(9)
Lower production taxes in 2004	—	16	16
<i>Other</i>			
Ceiling test and other charges in 2003.....	—	44	44
Other	(3)	3	—
<i>Total variance 2004 to 2003</i>	<u><u>\$ (132)</u></u>	<u><u>\$ 84</u></u>	<u><u>\$ (48)</u></u>

Operating Revenues. In 2004, we experienced a significant decrease in production volumes. The decline in our production volumes was due to production declines in the Offshore Gulf of Mexico and Texas Gulf Coast regions, asset sales in New Mexico in 2003, the impact of hurricanes in the Gulf of Mexico, significantly lower capital expenditures and disappointing drilling results. Partially offsetting the impact of lower production volumes were higher average realized prices for natural gas and oil, condensate and NGL and a favorable impact from our hedging program as our hedging losses were \$43 million in 2004 as compared to \$101 million in 2003.

Depreciation, depletion, and amortization expense. Lower production volumes in 2004 due to the production declines discussed above reduced our depreciation, depletion, and amortization expense. Partially offsetting this decrease were higher depletion rates due to higher finding and development costs.

Production costs. In 2004, we experienced higher workover costs due to the implementation of programs in the second half of 2004 to slow the production decline in the Offshore Gulf of Mexico and Texas Gulf Coast regions. More than offsetting these increases were lower production taxes as a result of lower production volumes and higher tax credits taken in 2004 on high cost natural gas wells. The cost per unit increased due to lower production volumes and higher lease operating costs previously discussed.

Other. In 2003, we incurred ceiling test charges of \$34 million related to our domestic full cost pool and \$5 million associated with our full cost pool in Brazil. In addition, we recorded an impairment charge of \$5 million, net of gains on asset sales, related to non-full cost pool assets. Included in the variance in other are general and administrative expenses that are allocated to the Production segment based on the relative contribution of its activities to El Paso's production activities as a whole, and not based solely on its production volumes. Our general and administrative expenses stayed relatively consistent from 2003 to 2004 as lower

allocated costs were offset by a decrease in the costs we capitalized. However, our expense per Mcfe of production increased by 44 percent from 2003 to 2004 due primarily to the decrease in production volumes year-over-year.

Non-regulated Business — Power Segment

As of December 31, 2004, our Power segment consists of our Asian power assets, our investment in the Midland Cogeneration Venture (MCV) domestic power facility, and other power businesses, primarily equity investments in Central America. Historically, this segment also included a domestic power contract restructuring business, which we sold in 2004. We have designated all of our power operations as non-core activities, and we continue to evaluate potential opportunities to sell or otherwise divest many of our remaining power assets. As this process progresses, we will continue to assess the value of these assets which may result in impairments.

Asia. Our Asian operations include equity investments in six power plants. These facilities sell electricity and electrical generating capacity under long-term power sales agreements with local transmission and distribution companies, many of which are government controlled. The majority of these contracts allow for changes in fuel costs to be passed through to the customer through power prices. The economic performance of these facilities is impacted by the level of electricity demand and changes in the political and regulatory environment in the countries they serve as well as the relative cost of producing that power. We recorded an impairment in 2004 in connection with our decision to sell these assets.

MCV. We have an equity ownership in a natural gas-fired power plant, MCV. The price of electricity sold by MCV is indexed to coal, while the plant is fueled by natural gas, which it purchases under both long-term contracts and on the spot market. Changes in the relationship between coal and natural gas prices directly impact the economic performance of this facility. In 2004, we recorded an impairment of our interest in this plant based on a decline in the value of the investment that we considered to be other than temporary.

Domestic Power Contract Restructuring Business. In 2002, we completed several contract restructuring transactions, the largest of which was Utility Contract Funding (UCF). During 2004, we completed the sale of all of the entities that hold our restructured power contracts.

Operating Results

Below are the overall operating results and analysis of activities within our Power segment for the years ended December 31. Substantial changes in the business during these periods affected year-to-year comparability.

	<u>2004</u>	<u>2003</u>
	(In millions)	
<i>Overall EBIT:</i>		
Gross margin ⁽¹⁾	\$ 100	\$ 174
Operating expenses		
Loss on long lived assets	(102)	(28)
Other operating expenses	<u>(95)</u>	<u>(124)</u>
Operating income (loss)	(97)	22
Earnings from unconsolidated affiliates		
Impairments, net of gains on sale	(288)	(43)
Equity in earnings	15	37
Other income	<u>21</u>	<u>23</u>
EBIT	<u><u>\$ (349)</u></u>	<u><u>\$ 39</u></u>
<i>Significant factors impacting EBIT:</i>		
<i>Asia</i>		
Earnings from plant operations	\$ 13	\$ 2
Impairment and write-off	(131)	—
<i>MCV</i>		
Earnings from plant operations	(10)	29
Impairment	(161)	—
<i>Domestic power contract restructuring activities</i>		
Increase in fair values	36	65
Impairments and gains (losses) on sale	(88)	7
<i>Other power assets</i>		
Earnings from consolidated and unconsolidated plant operations	2	14
Impairment and gain on sale of Bastrop equity investment	3	(43)
Other impairments, net of gains on sale	<u>(13)</u>	<u>(35)</u>
EBIT	<u><u>\$ (349)</u></u>	<u><u>\$ 39</u></u>

⁽¹⁾ Gross margin for our Power segment consists of revenues from our power plants and revenues, cost of electricity purchases and changes in fair value of restructured power contracts. The cost of fuel used in the power generation process is included in operating expenses.

Asia. During the fourth quarter of 2004, we recorded a \$131 million charge on our Asian power assets in connection with our decision to pursue the sale of these assets. These impairment amounts were based on our estimates of the fair value of these projects. In 2005, we engaged a financial advisor to assist us in the sale of these assets. As this process continues, we will continue to update the fair value of these assets, which may result in further impairments.

Our earnings from one of our equity investments in a power plant in Pakistan were \$12 million lower in 2003 as compared to 2004 primarily due to expenses incurred by the plant in 2003 associated with the resolution of construction-related issues. From 2003 to 2004, earnings from our other Asian power assets were relatively stable as the underlying plants maintained steady levels of availability and production. Higher fuel costs during these periods did not materially impact these plants' operations as substantially all of the higher fuel costs were passed through to the power purchasers through higher contracted power prices.

MCV. Our MCV power plant is a natural gas-fired plant, which sells its power at a contracted price that is indexed to coal prices. During 2004, MCV experienced reduced EBIT primarily because natural gas prices

increased at a faster rate than coal prices. This decrease in EBIT was magnified by an increase in the volume of power MCV was required to generate. In January 2005, MCV received regulatory approval to reduce the required level of power generation. In the fourth quarter of 2004, we impaired our investment in MCV based on a decline in the value of the investment due to increased fuel costs. We will continue to assess our ability to recover our investment in MCV and its related operations in the future.

Domestic Power Contract Restructuring Activities. We recorded impairments and gains (losses) on our interests in UCF and Mohawk River Funding IV related to the sale of these entities and their restructured power contracts in 2004 and 2003.

Other Power Assets. During 2003, we recorded an impairment of our Bastrop equity investment and two other consolidated power plants based on the anticipated sale of these assets.

As part of El Paso's long-term business strategy, we continue to evaluate potential opportunities to sell or otherwise divest of many of our remaining power assets. As these sales occur and/or as market indicators of fair value become available, it is possible that impairments of these assets may occur, which may be significant.

Non-regulated Businesses — Field Services Segment

Our Field Services segment has historically conducted our midstream activities through its portfolio of natural gas gathering and processing assets. We have sold a substantial portion of these assets in 2003 and 2004 such that our remaining assets principally consist of our gathering and processing assets in south Louisiana.

Below are the operating results and analysis of these results for our Field Services segment for each of the years ended December 31:

<u>Field Services Segment Results</u>	<u>2004</u>	<u>2003</u>
	<u>(In millions, except volumes and prices)</u>	
Gathering and processing gross margins ⁽¹⁾	\$ 86	\$ 59
Operating expenses		
Gain (loss) on long-lived assets	(5)	13
Other operating expenses	<u>(35)</u>	<u>(31)</u>
Operating income	46	41
Other income (expense)		
Impairments and gains (losses) on sale of unconsolidated affiliates	(4)	(85)
Other	<u>13</u>	<u>(8)</u>
EBIT	<u>\$ 55</u>	<u>\$ (52)</u>
Volumes and Prices:		
Gathering		
Volumes (BBtu/d)	<u>19</u>	<u>101</u>
Prices (\$/MMBtu)	<u>\$ 0.07</u>	<u>\$ 0.14</u>
Processing		
Volumes (inlet BBtu/d)	<u>1,618</u>	<u>1,687</u>
Prices (\$/MMBtu)	<u>\$ 0.14</u>	<u>\$ 0.11</u>

⁽¹⁾ Gross margins consist of operating revenues less cost of products sold. We believe this measurement is more meaningful for understanding and analyzing our Field Services segment's operating results because commodity costs play such a significant role in the determination of profit from our midstream activities.

Below is a summary of significant factors and related discussions affecting EBIT for each of the years ended December 31:

	<u>EBIT Impact</u>	
	<u>2004</u>	<u>2003</u>
Gathering and processing margins	\$ 86	\$ 59
Operating expenses	(35)	(31)
Equity earnings (losses)	14	(7)
Asset impairments and gains (losses) on sales		
Mid-Continent	—	19
Dauphin Island/Mobile Bay	—	(86)
Other	<u>(10)</u>	<u>(6)</u>
EBIT	<u>\$ 55</u>	<u>\$(52)</u>

Gathering and Processing Activities. Our gathering and processing margins were impacted by the spread between NGL prices and natural gas prices during 2003 and 2004. As these spreads increase, we generally increase the NGL volumes we extract, which affects our margin. In 2003, our margins were negatively impacted by a decrease in these spreads as natural gas prices relative to NGL prices increased, which also caused us to reduce the amount of NGL extracted. However, in 2004 these margins were positively impacted by an increase in these spreads as NGL prices improved. In the future, the margins of our remaining assets will remain sensitive to the spread between natural gas pricing and NGL pricing.

Asset Sales. During 2004 and 2003 we sold a substantial amount of our assets. Listed below are the significant transactions:

- 2003 — Sale of our Wyoming gathering assets and Mid-Continent gathering and processing assets. In addition, we recorded an impairment of our investments in Dauphin Island and Mobile Bay based on the pending sale.
- 2004 — Sale of our investments in Dauphin Island and Mobile Bay.

Interest and Debt Expense

Below is an analysis of our interest and debt expense for each of the years ended December 31 (in millions):

	<u>2004</u>	<u>2003</u>
Long-term debt, including current maturities	\$353	\$412
Other interest	2	6
Capitalized interest	<u>(14)</u>	<u>(11)</u>
Total interest and debt expense	<u>\$341</u>	<u>\$407</u>

Interest expense on long-term debt for the year ended December 31, 2004, was \$59 million lower than in 2003 due primarily to the retirement of \$1.9 billion of debt during 2003 and 2004, partially offset by interest on \$300 million of borrowings by ANR in 2003 and interest on \$300 million of Coastal Finance I preferred securities for a full year in 2004. In 2003, we reclassified the Coastal Finance I preferred securities from preferred interests of consolidated subsidiaries to long-term debt.

Affiliated Interest Expense, Net

Affiliated interest expense, net for the year ended December 31, 2004, was \$41 million lower than the same period in 2003, due to lower average balances partially offset by higher average short term interest rates for 2004. The average advance balances for the twelve months decreased from \$2,052 million in 2003 to less than \$24 million in 2004. The decrease in advances includes a \$1,500 million contribution from El Paso Corporation. The average short-term interest rates increased from 2.0% in 2003 to 2.4% in 2004.

Distributions on Preferred Interests of Consolidated Subsidiaries

Distributions on preferred interests of consolidated subsidiaries for the year ended December 31, 2004, were \$17 million lower than in 2003, primarily due to the redemption of Coastal Securities Company Limited preferred stock and the reclassification of Coastal Finance I mandatorily redeemable preferred securities to long-term financing obligations as a result of the adoption of SFAS No. 150. As a result of this reclassification, we began recording the preferred returns on these securities as interest expense rather than as distributions of preferred interests.

For a further discussion of our borrowings and other financing activities related to our consolidated subsidiaries, see Item 8, Financial Statements and Supplementary Data, Note 12.

Income Taxes

Income taxes for 2004 and 2003 have been revised to reflect the effects on income taxes of the restatements described in Part II, Item 8. Financial Statements and Supplementary Data, Note 1. Income taxes for the years ended December 31, 2004 and 2003 were \$12 million and \$43 million, resulting in effective tax rates of (41) percent and 18 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent were primarily a result of the following factors:

- state income taxes, net of federal income tax effect;
- foreign income/loss taxed at different rates;
- abandonments and sales of foreign investments;
- valuation allowances;
- non-taxable stock dividends; and
- dispositions of domestic assets.

For 2004, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to impairments of certain of our foreign investments for which there was no corresponding U.S. federal income tax benefit. This resulted in an overall tax expense for a period in which there was also a pre-tax loss.

For 2003, our overall effective tax rate on continuing operations was significantly different than the statutory rate due primarily to \$25 million of tax benefits related to abandonments and sales of certain of our foreign investments.

In October 2004, the American Jobs Creation Act of 2004 was signed into law. This legislation creates, among other things, a temporary incentive for U.S. multinational companies to repatriate accumulated income earned outside the U.S. at an effective tax rate of 5.25%. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not provided U.S. deferred taxes on foreign earnings where such earnings were intended to be indefinitely reinvested outside the U.S. We are currently evaluating whether we will repatriate any foreign earnings under the American Jobs Creation Act, and are evaluating the other provisions of this legislation, which may impact our taxes in the future.

As part of our long-term business strategy, we anticipate that we will sell our Asian power investments. As further discussed in Item 8, Financial Statements and Supplementary Data, Note 6, we have not historically recorded United States deferred taxes on book versus tax basis differences in these investments because our intent was to indefinitely reinvest earnings from these projects outside the United States. In 2004, our intent on these assets changed, and we now intend to use the proceeds from the sale within the U.S. As a result, we recorded U.S. deferred tax liabilities for those instances where the book basis in our investment exceeded the tax basis in 2004. At this time, however, due to uncertainties as to the manner, timing and approval of the anticipated sale transactions, we have not recorded U.S. deferred tax assets for those instances where the tax basis in our investment exceeded the book basis, except in instances where we believe the

realization of the asset is assured. As these uncertainties become known, we will record additional tax effects to reflect the ultimate sale transactions, the amounts of which could have a significant impact on our future recorded tax amounts and our effective tax rates in those periods.

Discontinued Operations

Our loss from discontinued operations for 2004 and 2003 has been restated to adjust the amount of losses on sales of assets and investments and related tax adjustments in our discontinued Canadian exploration and production operations and petroleum market operations which had CTA balances. For a further discussion see Part II, Item 8, Financial Statements and Supplementary Data, Note 1.

For the year ended December 2004, the loss from our discontinued operations was \$115 million compared to a loss of \$1.3 billion during 2003. In 2004, \$36 million of losses from discontinued operations related to our Canadian and certain other international production operations, primarily from losses on sales and impairment charges, and \$79 million was from our petroleum markets activities, primarily related to losses on the completed sales of our Eagle Point and Aruba refineries along with other operational and severance costs. The losses in 2003 related primarily to impairment charges on our Aruba and Eagle Point refineries and on chemical assets, all as a result of El Paso's decision to exit and sell these businesses and ceiling test charges related to our Canadian production operations.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 13, incorporated herein by reference.

New Accounting Pronouncements Issued But Not Yet Adopted

See Item 8, Financial Statements and Supplementary Data, Note 1 under *New Accounting Pronouncements Issued But Not Yet Adopted* which is incorporated herein by reference.

RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE “SAFE HARBOR” PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and in good faith, assumed facts or bases almost always vary from the actual results, and differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words “believe,” “expect,” “estimate,” “anticipate” and similar expressions will generally identify forward-looking statements. All of our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

With this in mind, you should consider the risks discussed elsewhere in this report and other documents we file with the SEC from time to time and the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

Risks Related to Our Business

Our operations are subject to operational hazards and uninsured risks.

Our operations are subject to the inherent risks normally associated with those operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires, and adverse weather conditions, and other hazards, each of which could result in damage to or destruction of our facilities or damages to persons and property. In addition, our operations face possible risks associated with acts of aggression on our domestic and foreign assets. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against many of these risks to the extent and in amounts that we believe are reasonable, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

The success of our pipeline business depends, in part, on factors beyond our control.

Most of the natural gas and natural gas liquids we transport and store are owned by third parties. As a result, the volume of natural gas and natural gas liquids involved in these activities depends on the actions of those third parties, which is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current throughput, to renegotiate existing contracts as they expire or to remarket unsubscribed capacity on our pipeline systems:

- service area competition;
- expiration and/or turn back of significant contracts;
- changes in regulation and action of regulatory bodies;
- future weather conditions;
- price competition;
- drilling activity and supply availability of natural gas;
- decreased availability of conventional gas supply sources and the availability and timing of other gas supply sources, such as LNG;
- increased availability or popularity of alternative energy sources such as hydroelectric power;

- increased cost of capital;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions;
- unfavorable movements in natural gas and liquids prices.

The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.

Substantially all of our pipeline subsidiaries' revenues are generated under contracts which expire periodically and must be renegotiated and extended or replaced. We cannot assure that we will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts.

In particular, our ability to extend and/or replace contracts could be adversely affected by factors we cannot control, including:

- competition by other pipelines, including the proposed construction by other companies of additional pipeline capacity or LNG terminals in markets served by our interstate pipelines;
- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire;
- reduced demand and market conditions in the areas we serve;
- the availability of alternative energy sources or gas supply points; and
- regulatory actions.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues, earnings and cash flows.

Fluctuations in energy commodity prices could adversely affect our pipeline businesses.

Revenues generated by our transmission, storage, and processing contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and natural gas liquids. Increased prices could result in a reduction of the volumes transported by our customers, such as power companies who, depending on the price of fuel, may not dispatch gas fired power plants. Increased prices could also result from industrial plant shutdowns or load losses to competitive fuels as well as local distribution companies' loss of customer base. We also experience earnings volatility when the amount of gas utilized in operations differs from amounts we receive for that purpose. The success of our transmission, storage and processing operations is subject to continued development of additional oil and natural gas reserves and our ability to access additional suppliers from interconnecting pipelines to offset the natural decline from existing wells connected to our systems. A decline in energy prices could precipitate a decrease in these development activities and could cause a decrease in the volume of reserves available for transmission, storage and processing through our systems or facilities. We retain a fixed percentage of natural gas transported for use as fuel and to replace lost and unaccounted for gas, and we are at risk for the difference between the retained amount and actual gas consumed or lost and unaccounted. Pricing volatility may also impact the value of under or over recoveries of this retained gas. If natural gas prices in the supply basins connected to our pipeline systems are higher on a delivered basis to our off-system markets than delivered prices from other natural gas producing regions, our ability to compete with other transporters may be negatively impacted. Fluctuations in energy prices are caused by a number of factors, including:

- regional, domestic and international supply and demand;
- availability and adequacy of transportation facilities;
- energy legislation;

- federal and state taxes, if any, on the sale or transportation of natural gas and natural gas liquids;
- abundance of supplies of alternative energy sources; and
- political unrest among oil producing countries.

Natural gas and oil prices are volatile. A substantial decrease in natural gas and oil prices could adversely affect the financial results of our exploration and production business.

Our future financial condition, revenues, results of operations, cash flows, and future rate of growth depend primarily upon the prices we receive for our natural gas and oil production. Natural gas and oil prices historically have been volatile and are likely to continue to be volatile in the future, especially given current world geopolitical conditions. The prices for natural gas and oil are subject to a variety of additional factors that are beyond our control. These factors include:

- the level of consumer demand for, and the supply of, natural gas and oil;
- commodity processing, gathering and transportation availability;
- the level of imports of, and the price of, foreign natural gas and oil;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- domestic governmental regulations and taxes;
- the price and availability of alternative fuel sources;
- the availability of pipeline capacity;
- weather conditions;
- market uncertainty;
- political conditions or hostilities in natural gas and oil producing regions;
- worldwide economic conditions; and
- decreased demand for the use of natural gas and oil because of market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives.

Further, because approximately 64 percent of our proved reserves at December 31, 2004 were natural gas reserves, we are substantially more sensitive to changes in natural gas prices than we are to changes in oil prices. Declines in natural gas and oil prices would not only reduce revenue, but could reduce the amount of natural gas and oil that we can produce economically and, as a result, could adversely affect the financial results of our production business. Changes in natural gas and oil prices have a significant impact on the calculation of our full cost ceiling test. A significant decline in natural gas and oil prices could result in a downward revision of our reserves and a write-down of the carrying value of our natural gas and oil properties, which could be substantial and would negatively impact our net income and stockholder's equity.

Our use of hedging arrangements may adversely affect our future results of operations or liquidity.

To reduce our exposure to fluctuations in the prices of natural gas and oil, we may use futures, swaps and option contracts traded on the New York Mercantile Exchange (NYMEX), over-the-counter options and price and basis swaps with other natural gas merchants and financial institutions. We also enter into hedging arrangements with El Paso Marketing. Hedging arrangements expose us to risk of financial loss in some circumstances, including when:

- expected production is less than the amount hedged;
- the counterparty to the hedging contract defaults on its contractual obligations; or

- there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received.

Our hedging arrangements may also limit the benefit we would receive from increases in the prices for natural gas and oil. The use of derivatives also may require the posting of cash collateral with counterparties which can impact working capital when commodity prices change. El Paso provides us with gas marketing and hedging services and we currently do not post cash collateral with counterparties. In addition, these hedging arrangements may impact the carrying value of our natural gas and oil properties in our full cost pool as we include hedges in our ceiling test calculation.

The success of our natural gas and oil exploration and production businesses is dependent, in part, on factors that are beyond our control.

In addition to prices, the performance of our natural gas and oil exploration and production businesses is dependent, in part, upon a number of factors that we cannot control, including:

- the results of future drilling activity;
- our ability to identify and precisely locate prospective geologic structures and to drill and successfully complete wells in those structures in a timely manner;
- our ability to expand our leased land positions in desirable areas, which often are subject to intensely competitive conditions;
- increased competition in the search for and acquisition of reserves;
- future drilling, production and development costs, including drilling rig rates and oil field services costs;
- future tax policies, rates, and drilling or production incentives by state, federal, or foreign governments;
- increased federal or state regulations, including environmental regulations, or adverse court decisions that limit or restrict the ability to drill natural gas or oil wells, reduce operational flexibility, or increase capital and operating costs;
- decreased demand for the use of natural gas and oil because of market concerns about global warming or changes in governmental policies and regulations due to climate change initiatives;
- declines in production volumes, including those from the Gulf of Mexico; and
- continued access to sufficient capital to fund drilling programs to develop and replace a reserve base with rapid depletion characteristics.

Our affiliate, El Paso Production Holding Company (El Paso Production), is a wholly owned direct subsidiary of El Paso. El Paso Production, through its subsidiaries, engages in the exploration for and the acquisition, development and production of natural gas and oil, primarily in the United States. We and El Paso Production do not have an agreement regarding the allocation of business opportunities.

In addition, our officers, directors and personnel also provide services to El Paso Production and its subsidiaries pursuant to our shared services arrangement and therefore share their time and services between us and El Paso Production. These persons may therefore have conflicts of interest between us and El Paso Production.

Our natural gas and oil drilling and producing operations involve many risks and may not be profitable.

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties and the drilling of natural gas and oil wells, including well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks. The nature of the risks is such that some liabilities could exceed our insurance policy limits, or, as in the case

of environmental fines and penalties, cannot be insured. As a result, we could incur substantial costs that could adversely affect our future results of operations, cash flows or financial condition.

In addition, in our drilling operations we are subject to the risk that we will not encounter commercially productive reservoirs. New wells drilled by us may not be productive, or we may not recover all or any portion of our investment in those wells. Drilling for natural gas and oil can be unprofitable, not only because of dry holes but wells that are productive may not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs.

Estimating our reserves, production and future net cash flow is difficult.

Estimating quantities of proved natural gas and oil reserves is a complex process that involves significant interpretations and assumptions. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. As a result, our reserve estimates are inherently imprecise. Also, the use of a 10 percent discount factor for estimating the value of our reserves, as prescribed by the SEC, may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our production business or the natural gas and oil industry, in general, are subject. Any significant variations from the interpretations or assumptions used in our estimates or changes of conditions could cause the estimated quantities and net present value of our reserves to differ materially.

Our reserve data represents an estimate. You should not assume that the present values referred to in this report represent the current market value of our estimated natural gas and oil reserves. The timing of the production and the expenses from development and production of natural gas and oil properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. Changes in the present value of these reserves could cause a write-down in the carrying value of our natural gas and oil properties, which could be substantial, and would negatively affect our net income and stockholder's equity.

As of December 31, 2004, approximately 32 percent of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of proved undeveloped reserves and proved but non-producing reserves are subject to greater uncertainties than estimates of proved producing reserves.

The success of our power activities depends, in part, on many factors beyond our control.

The success of our remaining domestic and international power projects could be adversely affected by factors beyond our control, including:

- alternative sources and supplies of energy becoming available due to new technologies and interest in self generation and cogeneration;
- increases in the costs of generation, including increases in fuel costs;
- uncertain regulatory conditions resulting from the ongoing deregulation of the electric industry in the United States and in foreign jurisdictions;
- our ability to negotiate successfully and enter into, advantageous power purchase and supply agreements;
- the possibility of a reduction in the projected rate of growth in electricity usage as a result of factors such as regional economic conditions, excessive reserve margins and the implementation of conservation programs;
- risks incidental to the operation and maintenance of power generation facilities;
- the inability of customers to pay amounts owed under power purchase agreements;

- the increasing price volatility due to deregulation and changes in commodity trading practices; and
- over-capacity of generation in markets served by the power plants we own or in which we have an interest.

Our businesses are subject to the risk of payment defaults by our counterparties.

We frequently extend credit to our counterparties following the performance of credit analysis. Despite performing this analysis, we are exposed to the risk that we may not be able to collect amounts owed to us. Although in many cases we have collateral to secure the counterparty's performance, it could be inadequate and we could suffer credit losses.

Our foreign operations and investments involve special risks.

Our activities in areas outside the United States are subject to the risks inherent in foreign operations, including:

- loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, wars, insurrection and other political risks;
- the effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies and other economic problems; and
- changes in laws, regulations and policies of foreign governments, including those associated with changes in the governing parties.

Retained liabilities associated with businesses that we have sold could exceed our estimates.

We have sold a significant number of assets over the years, including the sale of many assets since 2001. Pursuant to various purchase and sale agreements relating to businesses and assets that we have divested, we have either retained certain liabilities or indemnified certain purchasers against liabilities that they might incur in the future. These liabilities in many cases relate to breaches of warranties, environmental, tax, litigation, personal injury and other representations that we have provided. Although we believe that we have established appropriate reserves for these liabilities, we could be required to accrue additional reserves in the future and these amounts could be material. In addition, as we exit businesses, we have experienced substantial reductions and turnover in our workforce that previously supported the ownership and operation of such assets. There is the risk that such reductions and turnover in our workforce could result in errors or mistakes in managing the businesses that we are exiting prior to closing. There is also the risk that such reductions could result in errors or mistakes in managing the retained liabilities after closing, including the lack of any historical knowledge with regard to such assets and businesses in managing the liabilities or defending any associated litigation.

Risks Related to Legal and Regulatory Matters

Ongoing litigation and investigations related to the restatement of our financial statements associated with our reserve estimates could significantly adversely affect our business.

In 2004, we restated our historical financial statements as a result of a downward revision of our natural gas and oil reserves. As a result of this reduction in reserve estimates, several class action lawsuits were filed against us and several of our subsidiaries. The reserve revisions are also the subject of investigations by the SEC and the U.S. Attorney. These investigations and lawsuits, and possible future claims based on these same facts, may further negatively impact our credit ratings and place further demands on our liquidity. We cannot provide assurance at this time that the effects and results of these or other investigations or of the class action lawsuits will not be material to our financial conditions, results of operations and liquidity.

The agencies that regulate our pipeline businesses and their customers affect our profitability.

Our pipeline businesses are regulated by the FERC, the U.S. Department of Transportation, and various state and local regulatory agencies. Regulatory actions taken by those agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates our pipelines are permitted to charge their customers for their services. In setting authorized rates of return in a few recent FERC decisions, the FERC has utilized a proxy group of companies that includes local distribution companies that are not faced with as much competition or risks as interstate pipelines. The inclusion of these companies creates downward pressure on approved tariff rates. If our pipelines' tariff rates were reduced in a future proceeding, if our pipelines' volume of business under their currently permitted rates was decreased significantly, or if our pipelines were required to substantially discount the rates for their services because of competition or because of regulatory pressure, the profitability of our pipeline businesses could be reduced.

In addition, increased regulatory requirements relating to the integrity of our pipelines requires additional spending in order to maintain compliance with these requirements. Any additional requirements that are enacted could significantly increase the amount of these expenditures.

Further, state agencies that regulate our pipelines' local distribution company customers could impose requirements that could impact demand for our pipelines' services.

Costs of environmental liabilities, regulations and litigation could exceed our estimates.

Our operations are subject to various environmental laws and regulations. These laws and regulations obligate us to install and maintain pollution controls and to clean up various sites at which regulated materials may have been disposed of or released. Some of these sites have been designated as Superfund sites by the EPA under the Comprehensive Environmental Response, Compensation and Liability Act. We are also party to legal proceedings involving environmental matters pending in various courts and agencies.

Compliance with environmental laws and regulations can require significant costs, such as costs of clean-up and damages arising out of contaminated properties, and failure to comply with environmental laws and regulations may result in fines and penalties being imposed. It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the uncertainties in estimating pollution control and clean up costs;
- the discovery of new sites or information;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the nature of environmental laws and regulations; and
- potential changes in environmental laws and regulations, including changes in the interpretation and enforcement thereof.

Although we believe we have established appropriate reserves for liabilities, including clean up costs, we could be required to set aside additional reserves in the future due to these uncertainties, and these amounts could be material. For additional information concerning our environmental matters, see Part I, Item 3, Legal Proceedings, and Item 8, Financial Statements and Supplementary Data, Note 13.

Costs of litigation and other contingencies could exceed our estimates.

We are involved in various lawsuits in which we or our subsidiaries have been sued. We also have other contingent liabilities and exposures. Although we believe we have established appropriate reserves for these liabilities, we could be required to set aside additional reserves in the future and these amounts, and the effect of adverse judgments on our operations could be material. For additional information concerning these matters, see Part I, Item 3, Legal Proceedings, and Item 8, Financial Statements and Supplementary Data, Note 13.

Risks Related to Our Liquidity

We have significant debt, which impacted and will continue to impact our financial condition, results of operations and liquidity.

We have significant debt of approximately \$3.8 billion as of December 31, 2004 and have significant debt service and debt maturity obligations. Our expected debt maturities as of December 31, 2004 for 2005, 2006 and 2007 are \$310 million, \$330 million and \$8 million, respectively. If our ability to generate or access cash becomes significantly restrained, our financial condition and future results of operations could be significantly adversely affected. See Part II, Item 8, Financial Statements and Supplementary Data, Note 12, for a further discussion of our debt.

A breach of the covenants applicable to our debt and other financing obligations could affect our ability to borrow funds and could accelerate our debt and other financing obligations and those of our subsidiaries.

Our debt and other financing obligations contain restrictive covenants and cross-acceleration provisions. Some of our subsidiaries have covenants which become more restrictive over time. A breach of certain of these covenants could preclude our subsidiaries from issuing letters of credit and from borrowing under El Paso's \$3 billion credit agreement, and could accelerate our long-term debt and other financing obligations and those of our subsidiaries. If this were to occur, we may not be able to repay such debt and other financing obligations upon such acceleration.

We are a wholly owned direct subsidiary of El Paso and its financial condition and business strategy subjects us to potential risks that are beyond our control.

El Paso has substantial control over:

- our payment of dividends;
- decisions on our financings and our capital raising activities;
- mergers or other business combinations;
- our acquisitions or dispositions of assets; and
- our participation in El Paso's cash management program.

El Paso may exercise such control in its interests and not necessarily in the interests of us or the holders of our long-term debt.

Due to our relationship with El Paso, adverse developments or announcements concerning El Paso could adversely affect our financial condition, even if we have not suffered any similar development. The ratings assigned to El Paso's senior unsecured indebtedness are below investment grade, currently rated Caal by Moody's Investor Service (Moody's) and CCC+ by Standard & Poor's. Our senior unsecured indebtedness is rated Caal by Moody's and CCC+ by Standard & Poor's. These ratings have increased our cost of capital and collateral requirements, and could impede our access to capital markets. El Paso has realized substantial demands on its liquidity. El Paso's current ratings are a result, at least in part, of the outlook generally for the consolidated businesses of El Paso and its needs for liquidity.

El Paso continues its efforts to execute its Long Range Plan that established certain financial and other objectives, including asset sales and significant debt reduction. An inability to meet these objectives could adversely affect El Paso's liquidity position, and in turn affect our financial condition.

We participate in El Paso's cash management program, which matches cash surplus and needs for its participating affiliates. In addition, we conduct commercial transactions with some of our affiliates. As of December 31, 2004, we have net payables of approximately \$166 million to El Paso and its affiliates. El Paso provides cash management and other corporate services for us. If El Paso is unable to meet its liquidity needs, there can be no assurance that we will be able to access cash under the cash management program, or that our

affiliates could pay their obligations to us. However, we would be required to satisfy affiliated company payables, although we do not anticipate that El Paso will require us to repay these payables during 2005. Our inability to access the cash management program, recover any intercompany amounts owed to us, or a demand for payment of our affiliated payables could adversely affect our ability to repay our outstanding indebtedness. For a further discussion of our related party transactions, see Part II, Item 8, Financial Statements and Supplementary Data, Note 16.

Our system of internal controls are designed to ensure the accuracy and completeness of our disclosures and a loss of public confidence in the quality of our internal controls or disclosures could have a negative impact on us.

We are required to maintain an effective system of internal control over financial reporting. As a result of our efforts to comply with this requirement, we determined that as of December 31, 2004, we did not maintain effective internal control over financial reporting. As more fully discussed in Item 9A, we identified several deficiencies in internal control over financial reporting that management has concluded constituted material weaknesses. Although we have taken steps to remediate some of these deficiencies, additional steps must be taken to remediate the remaining control deficiencies. If we are unable to remediate our identified internal control deficiencies over financial reporting, or we identify additional deficiencies in our internal controls over financial reporting, we could be subjected to additional regulatory scrutiny, future delays in filing our financial statements and suffer a loss of public confidence in the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, which could have a negative impact on our liquidity, access to capital markets, and our financial condition.

In addition to the risk of not completing the remediation of all deficiencies in our internal controls over financial reporting, we do not expect that our disclosure controls and procedures or our internal controls over financial reporting will prevent all mistakes, errors and fraud. Any system of internal controls, no matter how well designed or implemented, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The design of a control system must reflect the fact that the benefits of controls must be considered relative to their costs. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Therefore, any system of internal controls is subject to inherent limitations, including the possibility that controls may be circumvented or overridden, that judgments in decision-making can be faulty, and that misstatements due to mistakes, errors or fraud may occur and may not be detected. Also, while we document our assumptions and review financial disclosures, the regulations and literature governing our disclosures are complex and reasonable persons may disagree as to their application to a particular situation or set of facts. In addition, the applicable regulations and literature are relatively new. As a result, they are potentially subject to change in the future, which could include changes in the interpretation of the existing regulations and literature as well as the issuance of more detailed rules and procedures.

Some of our assets are collateral for El Paso's Western Energy Settlement

One of our subsidiaries has pledged as collateral a portion of its natural gas and oil properties to support the obligations of some of our affiliates to make payments in connection with the settlement of various lawsuits arising out of the Western Energy Crisis. If our affiliates fail to make those payments, the properties that our subsidiary has pledged would be subject to foreclosure, which could have a material adverse effect on our financial position and liquidity, results of operations and cash flows.

Some of our assets are collateral for El Paso's \$3 billion credit agreement and other financing transactions.

Some of our subsidiaries are subsidiary guarantors of El Paso's \$3 billion credit agreement. In connection with these guarantees, El Paso pledged our ownership of ANR, ANR Storage, CIG, and WIC to collateralize the \$3 billion credit agreement. Our ownership in the above mentioned companies is subject to change if there is an event of default under the \$3 billion credit agreement and the lenders under this agreement exercise their rights over the collateral. If this were to occur, it could have a material adverse effect on our financial condition.

We could be substantively consolidated with El Paso if El Paso were forced to seek protection from its creditors in bankruptcy.

If El Paso were the subject of voluntary or involuntary bankruptcy proceedings, El Paso and its other subsidiaries and their creditors could attempt to make claims against us, including claims to substantively consolidate our assets and liabilities with those of El Paso and its other subsidiaries. The equitable doctrine of substantive consolidation permits a bankruptcy court to disregard the separateness of related entities and to consolidate and pool the entities' assets and liabilities and treat them as though held and incurred by one entity where the interrelationship between the entities warrants such consolidation. We believe that any effort to substantively consolidate us with El Paso and/or its other subsidiaries would be without merit. However, we cannot assure you that El Paso and/or its other subsidiaries or their respective creditors would not attempt to advance such claims in a bankruptcy proceeding or, if advanced, how a bankruptcy court would resolve the issue. If a bankruptcy court were to substantively consolidate us with El Paso and/or its other subsidiaries, there could be a material adverse effect on our financial condition and liquidity.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to several market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to and examples of each are:

- **Commodity Price Risk**
 - Natural gas prices change, impacting the forecasted sale of natural gas in our Production segment;
 - Price spreads between natural gas and natural gas liquids change, making the natural gas liquids we produce in our Field Services segment less valuable;
 - Electricity and natural gas prices change, affecting the value of our power contracts held in our Power segment.
- **Interest Rate Risk**
 - Changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of our fixed rate debt; and
 - Changes in interest rates used in the estimation of the fair value of our derivative positions can result in increases or decreases in the unrealized value of those positions.

We manage these risks by entering into contractual commitments involving physical or financial settlements that attempt to limit the amount of risk or opportunity related to future market movements, primarily related to movements in natural gas prices. Our risk management activities typically involve the use of forward contracts and financial swaps, many of which are derivative financial instruments. A discussion of our accounting policies for derivative instruments is included in Part II, Item 8, Financial Statements and Supplementary Data, Notes 1 and 8.

Commodity Price Risk

Our principal commodity price risks exist in our Production segment. Our Production segment attempts to mitigate commodity price risk and to stabilize cash flows associated with its forecasted sales of its natural gas and oil production through the use of derivative natural gas and oil swap contracts entered into with other El Paso affiliates. The table below presents the hypothetical sensitivity to changes in fair values arising from immediate selected potential changes in the quoted market prices of the natural gas swap contracts we used to mitigate these market risks that were outstanding at December 31, 2004 and 2003. Any gain or loss on these derivative commodity instruments would be substantially offset by a corresponding gain or loss on the hedged commodity positions, which are not included in the table.

	<u>Fair Value</u>	<u>10 Percent Increase</u>		<u>10 Percent Decrease</u>	
		<u>Fair Value</u>	<u>(Decrease)</u>	<u>Fair Value</u>	<u>Increase</u>
		(In millions)			
Impact of changes in commodity prices on derivative commodity instruments					
December 31, 2004	\$(148)	\$(177)	\$(29)	\$(119)	\$29
December 31, 2003	\$(124)	\$(148)	\$(24)	\$(100)	\$24

The derivatives described above do not hedge all of our commodity price risk related to our forecasted sales of our natural gas and oil production and as a result, we are subject to commodity price risks on our remaining forecasted natural gas and oil production.

Interest Rate Risk

Debt

Many of our debt-related financial instruments and project financing arrangements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related

weighted-average interest rates on our interest-bearing securities, by expected maturity dates and the fair values of those securities. As of December 31, 2004 and 2003, the fair value of the long-term securities has been estimated based on quoted market prices for the same or similar issues.

	December 31, 2004							December 31, 2003		
	Expected Fiscal Year of Maturity of Carrying Amounts							Carrying Amounts	Fair Value	
	2005	2006	2007	2008	2009	Thereafter	Total			Fair Value
	(Dollars in millions)									
Liabilities:										
Long-term debt and other financing obligations, including current portion — fixed rate	\$293	\$316	\$ —	\$ 415	\$200	\$2,495	\$3,719	\$3,893	\$5,080	\$4,992
Average interest rate . . .	8.6%	8.7%	—	7.1%	6.4%	8.2%				
Long-term debt, including current portion — variable rate	\$ 17	\$ 14	\$ 7	\$ —	\$ —	\$ —	\$ 38	\$ 38	\$ 241	\$ 241
Average interest rate . . .	5.8%	3.7%	2.3%	—	—	—				

Derivatives from Power Contract Restructuring Activities

During 2004, we sold our remaining third party long-term power purchase and our power supply derivative contracts held by Utility Contract Funding and Mohawk River Funding IV, which eliminated our exposure to interest rate risk related to these contracts.

Foreign Currency Exchange Rate Risk

Several of our international power plants in Asia and Central America have long-term power sales contracts that are denominated in the local country's currencies. As a result, we are subject to foreign currency exchange risk related to these power sales contracts. We do not believe that this exposure is material to our operations and have not chosen to mitigate this exposure.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements

Below is an index to the financial statements and notes contained in Item 8, Financial Statements and Supplementary Data.

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EL PASO CGP COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	<u>Year Ended December 31,</u>		
	<u>2004</u> <u>(Restated)</u>	<u>2003</u> <u>(Restated)</u>	<u>2002</u>
Operating revenues			
Pipelines	\$ 858	\$ 918	\$ 934
Production	690	822	1,187
Power	149	252	1,216
Field Services	482	356	460
Corporate and eliminations	<u>(2)</u>	<u>(17)</u>	<u>(15)</u>
	<u>2,177</u>	<u>2,331</u>	<u>3,782</u>
Operating expenses			
Cost of products and services	537	540	1,087
Operation and maintenance	530	528	755
Depreciation, depletion and amortization	467	487	609
Ceiling test charges	—	39	422
Loss (gain) on long-lived assets	106	8	(12)
Taxes, other than income taxes	<u>62</u>	<u>81</u>	<u>76</u>
	<u>1,702</u>	<u>1,683</u>	<u>2,937</u>
Operating income	475	648	845
Earnings (losses) from unconsolidated affiliates	(193)	(12)	113
Other income	44	66	70
Other expenses	(14)	5	(70)
Interest and debt expense	(341)	(407)	(425)
Affiliated interest expense, net	—	(41)	(9)
Distributions on preferred interests of consolidated subsidiaries	<u>—</u>	<u>(17)</u>	<u>(35)</u>
Income (loss) before income taxes	(29)	242	489
Income taxes	<u>12</u>	<u>43</u>	<u>143</u>
Income (loss) from continuing operations	(41)	199	346
Discontinued operations, net of income taxes	(115)	(1,286)	(395)
Cumulative effect of accounting changes, net of income taxes	<u>—</u>	<u>(12)</u>	<u>14</u>
Net loss	<u>\$ (156)</u>	<u>\$ (1,099)</u>	<u>\$ (35)</u>

See accompanying notes.

EL PASO CGP COMPANY
CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31,	
	2004 (Restated)	2003 (Restated)
ASSETS		
Current assets		
Cash and cash equivalents	\$ 80	\$ 150
Accounts and notes receivable		
Customer, net of allowance of \$29 in 2004 and \$37 in 2003	281	291
Affiliates	264	442
Other	93	86
Inventory	58	55
Assets from price risk management activities	—	97
Assets held for sale and from discontinued operations	106	1,406
Deferred income taxes	87	31
Other	49	93
Total current assets	<u>1,018</u>	<u>2,651</u>
Property, plant and equipment, at cost		
Natural gas and oil properties, at full cost	7,153	7,230
Pipelines	7,040	6,478
Power facilities	373	372
Gathering and processing systems	141	151
Other	89	119
	<u>14,796</u>	<u>14,350</u>
Less accumulated depreciation, depletion and amortization	7,997	8,003
Total property, plant and equipment, net	<u>6,799</u>	<u>6,347</u>
Other assets		
Investments in unconsolidated affiliates	894	1,312
Assets from price risk management activities	—	845
Goodwill and other intangible assets, net	426	415
Other	207	840
	<u>1,527</u>	<u>3,412</u>
Total assets	<u>\$9,344</u>	<u>\$12,410</u>

See accompanying notes.

EL PASO CGP COMPANY
CONSOLIDATED BALANCE SHEETS — (Continued)
(In millions, except share amounts)

	December 31,	
	2004 (Restated)	2003 (Restated)
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts payable		
Trade	\$ 234	\$ 196
Affiliates	61	67
Other	214	201
Current maturities of long-term debt	310	310
Notes payable to affiliates	211	949
Liabilities from price risk management activities	148	43
Liabilities related to discontinued operations	11	696
Other	279	320
Total current liabilities	1,468	2,782
Long-term financing obligations, less current maturities	3,447	5,011
Other		
Liabilities from price risk management activities	—	81
Deferred income taxes	692	734
Other	388	351
	1,080	1,166
Commitments and contingencies		
Securities of subsidiaries	158	107
Stockholder's equity		
Common stock, par value \$1 per share; authorized and issued 1,000 shares	—	—
Additional paid-in capital	3,181	3,136
Retained earnings	103	259
Accumulated other comprehensive loss	(93)	(51)
Total stockholder's equity	3,191	3,344
Total liabilities and stockholder's equity	\$9,344	\$12,410

See accompanying notes.

EL PASO CGP COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2004 (Restated) ⁽¹⁾	2003 (Restated) ⁽¹⁾	2002
Cash flows from operating activities			
Net loss	\$ (156)	\$(1,099)	\$ (35)
Less loss from discontinued operations, net of tax	(115)	(1,286)	(395)
Net income (loss) before discontinued operations	(41)	187	360
Adjustment to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion, and amortization	467	487	609
Ceiling test charges	—	39	422
Deferred income tax expense (benefit)	(43)	(39)	171
Loss (gain) on long-lived assets	106	8	(12)
Losses from unconsolidated affiliates, adjusted for cash distributions	299	103	28
Other non-cash items	12	6	34
Asset and liability changes			
Accounts and notes receivable	39	442	(472)
Inventory	(3)	2	53
Change in non-hedging price risk management activities, net	6	22	(480)
Accounts payable	35	(91)	(312)
Other asset and liability changes			
Assets	(37)	43	219
Liabilities	(50)	13	(124)
Cash provided by continuing operations	790	1,222	496
Cash provided by (used in) discontinued operations	220	(78)	(241)
Net cash provided by operating activities	<u>1,010</u>	<u>1,144</u>	<u>255</u>
Cash flows from investing activities			
Additions to property, plant, and equipment	(816)	(862)	(1,219)
Purchases of interests in equity investments	(12)	(4)	(45)
Net proceeds from the sale of assets and investments	87	313	1,638
Net change in restricted cash	21	(18)	(59)
Net change in notes receivable from affiliates	171	(109)	(102)
Other	48	(35)	(19)
Cash provided by (used in) continuing operations	(501)	(715)	194
Cash provided by (used in) discontinued operations	1,142	471	(291)
Net cash provided by (used in) investing activities	<u>641</u>	<u>(244)</u>	<u>(97)</u>

⁽¹⁾ Only individual line items within cash flows from operating activities have been restated. Total cash flows from continuing operating activities, investing activities, and financing activities, as well as discontinued operations were unaffected by our restatements.

See accompanying notes.

EL PASO CGP COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)
(In millions)

	Year Ended December 31,		
	2004 (Restated) ⁽¹⁾	2003 (Restated) ⁽¹⁾	2002
Cash flow from financing activities			
Net repayments under commercial paper and short-term credit facilities	—	—	(30)
Capital contribution from parent company	—	1,500	—
Net proceeds from the issuance of long-term debt and other financing obligations	—	288	882
Payments to retire long-term debt and other financing obligations	(692)	(638)	(1,240)
Payments to minority interest holders and preferred interests holders	—	(100)	(510)
Net change in notes payable to unconsolidated affiliates	—	(7)	(56)
Net change in affiliated advances payable	(738)	(1,404)	1,317
Dividends paid	—	(517)	—
Proceeds from issuance of securities of subsidiaries	75	—	33
Other	(2)	—	(6)
Contributions from (distributions to) discontinued operations	998	393	(1,093)
Cash used in continuing operations	(359)	(485)	(703)
Cash provided by (used in) discontinued operations	(1,362)	(393)	542
Net cash used in financing activities	(1,721)	(878)	(161)
Change in cash and cash equivalents	(70)	22	(3)
Less change in cash and cash equivalents related to discontinued operations	—	—	10
Change in cash and cash equivalents from continuing operations	(70)	22	(13)
Cash and cash equivalents			
Beginning of period	150	128	141
End of period	\$ 80	\$ 150	\$ 128
Supplemental Cash Flow Information:			
Interest paid, net of amounts capitalized	\$ 369	\$ 473	\$ 438
Income tax payments (refunds)	50	92	(23)

⁽¹⁾ Only individual line items within cash flows from operating activities have been restated. Total cash flows from continuing operating activities, investing activities, and financing activities, as well as discontinued operations were unaffected by our restatements.

See accompanying notes.

EL PASO CGP COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY
(In millions except share amounts)

	For the Years Ended December 31,					
	2004		2003		2002	
	(Restated)	(Restated)	(Restated)	(Restated)	(Restated)	(Restated)
	<u>Shares</u>	<u>Amount</u>	<u>Shares</u>	<u>Amount</u>	<u>Shares</u>	<u>Amount</u>
Common stock, par value \$1 per share, authorized 1,000 shares						
Balance at beginning of year	1,000	\$ —	1,000	\$ —	1,000	\$ —
Balance at end of year	<u>1,000</u>	<u>—</u>	<u>1,000</u>	<u>—</u>	<u>1,000</u>	<u>—</u>
Additional paid-in capital						
Balance at beginning of year		3,136		1,616		1,305
Capital contribution from El Paso		45		1,524		309
Other		<u>—</u>		<u>(4)</u>		<u>2</u>
Balance at end of year		<u>3,181</u>		<u>3,136</u>		<u>1,616</u>
Retained earnings						
Balance at beginning of year		259		1,875		1,910
Net loss		(156)		(1,099)		(35)
Dividends to parent		<u>—</u>		<u>(517)</u>		<u>—</u>
Balance at end of year		<u>103</u>		<u>259</u>		<u>1,875</u>
Accumulated other comprehensive income (loss)						
Balance at beginning of year		(51)		(139)		283
Other comprehensive income (loss)		<u>(42)</u>		<u>88</u>		<u>(422)</u>
Balance at end of year		<u>(93)</u>		<u>(51)</u>		<u>(139)</u>
Total stockholder's equity		<u>\$3,191</u>		<u>\$ 3,344</u>		<u>\$3,352</u>

See accompanying notes.

EL PASO CGP COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	<u>Year Ended December 31,</u>		
	<u>2004</u> <u>(Restated)</u>	<u>2003</u> <u>(Restated)</u>	<u>2002</u>
Net loss	\$ (156)	\$ (1,099)	\$ (35)
Foreign currency translation adjustments (net of income tax benefit of \$36 in 2004 and income tax expense of \$36 in 2003)	(33)	76	(14)
Minimum pension liability accrual (net of income tax of \$2 in 2004, \$1 in 2003 and \$7 in 2002)	(3)	(5)	(12)
Net gains (losses) from cash flow hedging activities:			
Unrealized mark-to-market losses arising during period (net of income tax of \$15 in 2004, \$24 in 2003 and \$140 in 2002)	(26)	(42)	(240)
Reclassification adjustments for changes in initial value to settlement date (net of income tax of \$12 in 2004, \$34 in 2003 and \$87 in 2002)	<u>20</u>	<u>59</u>	<u>(156)</u>
Other comprehensive income (loss)	<u>(42)</u>	<u>88</u>	<u>(422)</u>
Comprehensive loss	<u>\$ (198)</u>	<u>\$ (1,011)</u>	<u>\$ (457)</u>

See accompanying notes.

EL PASO CGP COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned and/or controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our results for all periods presented reflect our Canadian and certain other international natural gas and oil production operations, petroleum markets and coal mining businesses as discontinued operations. Additionally, our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications did not impact our reported net loss or stockholder's equity.

Restatement

Cumulative Foreign Currency Translation Adjustments (CTA). We determined that our CTA balances in accumulated other comprehensive loss incorrectly contained amounts related to businesses that had been previously sold or abandoned. These businesses included our discontinued Canadian exploration and production operations and certain of our discontinued petroleum markets activities. The adjustment of these CTA balances also affected the loss we recorded in 2004 on the sale of our Canadian operations.

In conjunction with the revisions for CTA, we also determined that upon initially recognizing deferred income taxes on our Canadian exploration and production operations, we did not properly allocate taxes to CTA in 2003. These allocated amounts then impacted the 2004 loss we recorded on the sale of our Canadian operations.

The overall impact of these adjustments for CTA and their related tax impact was a \$32 million reduction in our net loss from discontinued operations in 2004. In 2003, the overall impact of these adjustments was a reduction in our net loss from discontinued operations of \$35 million. As of December 31, 2004, the effect of these adjustments to total stockholders' equity was a \$1 million decrease resulting from an increase in retained earnings of \$67 million and an increase in accumulated other comprehensive loss of \$68 million.

Below are the effects of the restatements related to income taxes and CTA on our income statements, balance sheets and statements of comprehensive income. We have reflected these restatements in Notes 2, 6, 8, and 15.

	For the Year Ended December 31,			
	2004		2003	
	As Reported	As Restated	As Reported	As Restated
	(In millions)			
Income Statement:				
Discontinued operations, net of income taxes	\$(147)	\$(115)	\$(1,321)	\$(1,286)
Net loss	(188)	(156)	(1,134)	(1,099)
Statement of Comprehensive Income				
Foreign currency translation adjustment	\$ (1)	\$ (33)	\$ 112	\$ 76
Other comprehensive income (loss)	(10)	(42)	124	88

	As of December 31,			
	2004		2003	
	<u>As Reported</u>	<u>As Restated</u>	<u>As Reported</u>	<u>As Restated</u>
	(In millions)			
Balance Sheet:				
Deferred income tax assets, current	\$ 87	\$ 87	\$ 30	\$ 31
Deferred income tax liabilities, non-current	691	692	732	734
Retained earnings	36	103	224	259
Accumulated other comprehensive loss . . .	(25)	(93)	(15)	(51)
Total stockholder's equity	3,192	3,191	3,345	3,344

Principles of Consolidation

We consolidate entities when we either (i) have the ability to control the operating and financial decisions and policies of that entity or (ii) are allocated a majority of the entity's losses and/or returns through our variable interests in that entity. The determination of our ability to control or exert significant influence over an entity and whether we are allocated a majority of the entity's losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control, the decisions and policies of an entity and where we are not allocated a majority of the entity's losses and/or returns. We use the cost method of accounting where we are unable to exert significant influence over the entity. For a further discussion of the implementation of an accounting standard that impacted our consolidation principles beginning January 1, 2004, see below.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Accounting for Regulated Operations

Our interstate natural gas pipelines and storage operations are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Of our regulated pipelines, CIG, WIC and CPG follow the regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. ANR and ANR Storage discontinued the application of SFAS No. 71 in 1996. The accounting required by SFAS No. 71 differs from the accounting required for businesses that do not apply its provisions. Transactions that are generally recorded differently as a result of applying regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, postretirement employee benefit plans, and other costs included in, or expected to be included in, future rates. Effective December 31, 2004, ANR Storage began re-applying the provisions of SFAS No. 71.

We perform an annual review to assess the applicability of the provisions of SFAS No. 71 to our financial statements, the outcome of which could result in the re-application of this accounting in some of our regulated systems or the discontinuance of this accounting in others.

Cash and Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

We maintain cash on deposit with banks and insurance companies that is pledged for a particular use or restricted to support a potential liability. We classify these balances as restricted cash in other current or non-current assets in our balance sheet based on when we expect this cash to be used. As of

December 31, 2004 we had \$11 million of restricted cash in other current assets and \$18 million in other non-current assets. As of December 31, 2003, we had \$36 million of restricted cash in other current assets and \$43 million in other non-current assets.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts and notes receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

Inventory

Our inventory consists of natural gas and NGL in storage and materials and supplies. We classify all inventory as current or non-current based on whether it will be sold or used in the normal operating cycle of the assets, to which it relates, which is typically within the next twelve months. We use the average cost method to account for our inventories. We value all inventory at the lower of its cost or market value.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and in our regulated businesses that apply the provisions of SFAS No. 71, an equity return component. We capitalize the major units of property replacements or improvements and expense minor items. Included in our pipeline property balances are additional acquisition costs, which represent the excess purchase costs associated with purchase business combinations allocated to our regulated interstate systems. These costs are amortized on a straight-line basis, and we do not recover these excess costs in our rates. The following table presents our property, plant and equipment by type, depreciation method and depreciable lives:

<u>Type</u>	<u>Method</u>	<u>Depreciable Lives</u> (In years)
Regulated interstate systems		
SFAS No. 71	Composite ⁽¹⁾	1-51
Non-SFAS No. 71	Composite ⁽¹⁾	1-64
Non-regulated systems		
Transmission and storage facilities	Straight-line	35
Power facilities	Straight-line	3-22
Gathering and processing systems	Straight-line	3-33
Buildings and improvements	Straight-line	15-40
Office and miscellaneous equipment	Straight-line	3-10

⁽¹⁾ For our regulated interstate systems, we use the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar useful lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate approved in our rate settlements to the total cost of the group until its net book value equals its salvage value. We re-evaluate depreciation rates each time we redevelop our transportation rates when we file with the FERC for an increase or decrease in rates.

When we retire regulated property, plant and equipment, we charge accumulated depreciation and amortization for the original cost, plus the cost to remove, sell or dispose, less its salvage value. We do not recognize a gain or loss unless we sell an entire operating unit. We include gains or losses on dispositions of operating units in income.

We capitalize a carrying cost on funds invested in our construction of long-lived assets. This carrying cost consists of (i) an interest cost on our debt that could be attributed to the assets, which applies to all our businesses and (ii) a return on our equity, that could be attributed to the assets, which only applies to regulated transmission businesses that apply SFAS No. 71. The debt portion is calculated based on the average cost of debt. Interest cost on debt amounts capitalized during the years ended December 31, 2004, 2003 and 2002, were \$14 million, \$11 million and \$14 million. These amounts are included as a reduction of interest expense in our income statements. The equity portion is calculated using the most recent FERC

approved equity rate of return. These amounts are included as other non-operating income on our income statement. Capitalized carrying costs for debt and equity financed construction are reflected as an increase in the cost of the asset on our balance sheet.

Asset and Investment Impairments

We apply the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, and Accounting Principles Board Opinion (APB) No. 18, *The Equity Method of Accounting for Investments in Common Stock*, to account for asset and investment impairments. Under these standards, we evaluate an asset or investment for impairment when events or circumstances indicate that its carrying value may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of our carrying value based on either (i) the long-lived asset's ability to generate future cash flows on an undiscounted basis or (ii) the fair value of our investment in unconsolidated affiliates. If an impairment is indicated or if we decide to exit or sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to their estimated fair value, less costs to sell. Our fair value estimates are generally based on market data obtained through the sales process or an analysis of expected discounted cash flows. The magnitude of any impairments are impacted by a number of factors, including the nature of the assets to be sold and our established time frame for completing the sales, among other factors. We also reclassify the asset or assets as either held-for-sale or as discontinued operations, depending on, among other criteria, whether we will have any continuing involvement in the cash flows of those assets after they are sold.

Natural Gas and Oil Properties

We use the full cost method to account for our natural gas and oil properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves are capitalized. These capitalized amounts include the costs of unproved properties, internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. This method differs from the successful efforts method of accounting for these activities. The primary differences between these two methods are the treatment of exploratory dry hole costs. These costs are generally expensed under successful efforts when the determination is made that measurable reserves do not exist. Geological and geophysical costs are also expensed under the successful efforts method. Under the full cost method, both dry hole costs and geological and geophysical costs are capitalized into the full cost pool which is then periodically assessed for recoverability as discussed below.

We amortize capitalized costs using the unit of production method over the life of our proved reserves. Capitalized costs associated with unproved properties are excluded from the amortizable base until these properties are evaluated. Future development costs and dismantlement, restoration and abandonment costs, net of estimated salvage values, are included in the amortizable base. Beginning January 1, 2003, we began capitalizing asset retirement costs associated with proved developed natural gas and oil reserves into our full cost pool, pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations* as discussed below.

Our capitalized costs, net of related income tax effects, are limited to a ceiling based on the present value of future net revenues using end of period spot prices discounted at 10 percent, plus the lower of cost or fair market value of unproved properties, net of related income tax effects. If these discounted revenues are not greater than or equal to the total capitalized costs, we are required to write-down our capitalized costs to this level. We perform this ceiling test calculation each quarter. Any required write-downs are included in our income statement as a ceiling test charge. Our ceiling test calculations include the effects of derivative instruments we have designated as, and that qualify as, cash flow hedges of our anticipated future natural gas and oil production.

When we sell or convey interests (including net profits interests) in our natural gas and oil properties, we reduce our reserves for the amount attributable to the sold or conveyed interest. We do not recognize a gain or

loss on sales of our natural gas and oil properties, unless those sales would significantly alter the relationship between capitalized costs and proved reserves. We treat sales proceeds on non-significant sales as an adjustment to the cost of our properties.

Goodwill and Other Intangible Assets

Our intangible assets consist of goodwill resulting from acquisitions and other intangible assets. We apply SFAS No. 141, *Business Combinations*, and SFAS No. 142, *Goodwill and Other Intangible Assets*, to account for these intangibles. Under these standards, goodwill and intangibles that have indefinite lives are not amortized, but instead are periodically tested for impairment, at least annually, and whenever an event occurs that indicates that an impairment may have occurred. We amortize all other intangible assets on a straight-line basis over their estimated useful lives.

The net carrying amount of our goodwill as of December 31, 2004 and 2003 was \$413 million, all of which is included in our Pipelines segment. There was no change in the net carrying amount of our goodwill for the year ended December 31, 2004.

We also had other miscellaneous intangible assets of \$13 million and \$2 million as of December 31, 2004 and 2003.

Pension and Other Postretirement Benefits

El Paso maintains several pension and other postretirement benefit plans. These plans require us to make contributions to fund the benefits to be paid out under the plans. These contributions are invested until the benefits are paid out to plan participants. We record benefit expense related to these plans in our income statement. This benefit expense is a function of many factors including benefits earned during the year by plan participants (which is a function of the employee's salary, the level of benefits provided under the plan, actuarial assumptions, and the passage of time), expected return on plan assets and recognition of certain deferred gains and losses as well as plan amendments.

We compare the benefits earned, or the accumulated benefit obligation, to the plan's fair value of assets on an annual basis. To the extent the plan's accumulated benefit obligation exceeds the fair value of plan assets, we record a minimum pension liability in our balance sheet equal to the difference in these two amounts. We do not record an additional minimum liability if it is less than the liability already accrued for the plan. If this difference is greater than the pension liability recorded on our balance sheet, however, we record an additional liability and an amount to other comprehensive loss, net of income taxes, on our financial statements.

In 2004 we adopted FASB Staff Position (FSP) No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003*. This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits that are covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by \$5 million, which is deferred as an actuarial gain in our postretirement benefit liabilities as of December 31, 2004. We expect that the adoption of this guidance will reduce our postretirement benefit expense by approximately \$1 million in 2005.

Revenue Recognition

Our business segments provide a number of services and sell a variety of products. Our revenue recognition policies by segment are as follows:

Pipelines revenues. Our Pipelines segment derives revenues primarily from transportation and storage services. We also derive revenue from sales of natural gas. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity over the contract period regardless of the amount that is actually used. For interruptible or volumetric based services, and for revenues under natural gas sales contracts, we record revenues when we complete the delivery of natural gas to the agreed upon delivery point

and when natural gas is injected or withdrawn from the storage facility. Revenues in all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract or tariff. We are subject to FERC regulations and, as a result, revenues we collect may be refunded in a final order of a pending or future rate proceeding or as a result of a rate settlement. We establish reserves for these potential refunds.

Production revenues. Our Production segment derives revenues primarily through the physical sale of natural gas, oil, condensate and NGL. Revenues from sales of these products are recorded upon the passage of title using the sales method, net of any royalty interests or other profit interests in the produced product. When actual natural gas sales volumes exceed our entitled share of sales volumes, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability. Costs associated with the transportation and delivery of our production are included in cost of sales.

Power revenues. Our Power segment derives revenues from a number of sources including physical sales of power and the management of its derivative contracts. Our derivative transactions are recorded at their fair value, and changes in their fair value are reflected in operating revenues. See a discussion of our income recognition policies on derivatives below under *Price Risk Management Activities*. Revenues on physical sales are recognized at the time the commodity is delivered and are based on the volumes delivered and the contracted or market price.

Field Services revenues. Our Field Services segment derives revenues principally from gathering and processing services and through the sale of commodities that are retained from providing these services. There are two general types of service: fee-based and make-whole. For fee-based services we recognize revenues at the time service is rendered based upon the volume of gas gathered, treated or processed at the contracted fee. For make-whole services, our fee consists of retainage of natural gas liquids and other by-products that are a result of processing, and we recognize revenues on these services at the time we sell these products, which generally coincides with when we provide the service.

Environmental Costs and Other Contingencies

We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. We recognize a current period expense for the liability when clean-up efforts do not benefit future periods. We capitalize costs that benefit more than one accounting period, except in instances where separate agreements or legal or regulatory guidelines dictate otherwise. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the EPA or other organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage or government sponsored programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Price Risk Management Activities

Our price risk management activities primarily consist of derivatives entered into to hedge the commodity price risks on our natural gas and oil production and derivatives related to our power contract restructuring business.

We account for all derivative instruments under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*. Under SFAS No. 133, derivatives are reflected in our balance sheet at their fair value as assets and liabilities from price risk management activities. We classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities for counterparties where we have a legal right of offset. See Note 8 for a further discussion of our price risk management activities.

Our income statement treatment of changes in fair value and settlements of derivatives depends on the nature of the derivative instrument. Derivatives used in our hedging activities are reflected as either revenues or expenses in our income statements based on the nature and timing of the hedged transaction. Derivatives related to our power contract restructuring activities are reflected as either revenues (for settlements and changes in the fair values of the power sales contracts) or expenses (for settlements and changes in the fair values of the power supply agreements). Prior to 2003, we also had derivative contracts related to our historical trading activities.

In our cash flow statement, cash inflows and outflows associated with the settlement of our derivative instruments are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported as trade receivables and payables in our balance sheet.

During 2002, we also adopted Derivatives Implementation Group (DIG) Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract*. DIG Issue No. C-16 requires that if a fixed-price fuel supply contract allows the buyer to purchase, at their option, additional quantities at a fixed price, the contract is a derivative that must be recorded at its fair value. One of our unconsolidated affiliates, MCV, recognized a gain on one of its fuel supply contracts upon adoption of these new rules, and we recorded our proportionate share of this gain of \$14 million, net of income taxes, as a cumulative effect of an accounting change in our income statement.

Income Taxes

El Paso maintains a tax accrual policy to record both regular and alternative minimum tax for companies included in its consolidated federal and state income tax returns. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal and state income taxes, and (ii) each company in a tax loss position will accrue a benefit to the extent its deductions, including general business credits, can be utilized in the consolidated returns. El Paso pays all consolidated U.S. federal and state income taxes directly to the appropriate taxing jurisdictions and, under a separate tax billing agreement, El Paso may bill or refund its subsidiaries for their portion of these income tax payments.

Pursuant to El Paso's policy, we report current income taxes based on our taxable income, and we provide for deferred income taxes to reflect estimated future tax payments or receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

Foreign Currency Transactions and Translation

We record all currency transaction gains and losses in income. These gains or losses are classified in our income statement based upon the nature of the transaction that gives rise to the currency gain or loss. For sales and purchases of commodities or goods, these gains or losses are included in operating revenue or expense. These gains and losses were insignificant in 2004, 2003 and 2002. For gains and losses arising through equity investees, we record these gains or losses as equity earnings. For gains or losses on foreign denominated debt, we include these gains or losses as a component in other expense. For the years ended December 31, 2004, 2003 and 2002 the net foreign currency loss recorded in other expense was insignificant. The U.S. dollar is the

functional currency for the majority of our foreign operations. For foreign operations whose functional currency is deemed to be other than the U.S. dollar, assets and liabilities are translated at year-end exchange rates and the translation effects are included as a separate component of accumulated other comprehensive income (loss) in stockholder's equity. The net cumulative currency translation gain (loss) recorded in accumulated other comprehensive income (loss) was \$(6) million and \$27 million at December 31, 2004 and 2003. Revenues and expenses are translated at average exchange rates prevailing during the year.

Accounting for Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, which requires that we record a liability for retirement and removal costs of long-lived assets used in our business. Our asset retirement obligations are associated with our natural gas and oil wells and related infrastructure in our Production segment and our natural gas storage wells in our Pipelines segment. We have obligations to plug wells when production on those wells is exhausted, and we abandon them. We currently forecast that these obligations will be met at various times, generally over the next fifteen years, based on the expected productive lives of the wells and the estimated timing of plugging and abandoning those wells.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including credit-adjusted discount rates, projected inflation rates, and the estimated timing and amounts of settling our obligations, which are based on internal models and external quotes. The following is a summary of our asset retirement liabilities and the significant assumptions we used at December 31:

	<u>2004</u>	<u>2003</u>
	(In millions, except for rates)	
Current asset retirement liability	\$ 25	\$ 17
Non-current asset retirement liability ⁽¹⁾	\$ 140	\$122
Discount rates	6-8%	8-10%
Inflation rates	2.5%	2.5%

⁽¹⁾ We estimate that approximately 64% of our non-current asset retirement liability as of December 31, 2004 will be settled in the next five years.

Our asset retirement liabilities are recorded at their estimated fair value utilizing the assumptions above, with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the remaining useful life of the long-lived asset to which that liability relates. An ongoing expense is also recognized for changes in the value of the liability as a result of the passage of time, which we record in depreciation, depletion and amortization expense in our income statement. In the first quarter of 2003, we recorded a charge as a cumulative effect of accounting change of approximately \$12 million, net of income taxes, related to our adoption of SFAS No. 143.

The net asset retirement liability as of December 31, reported in other current and non-current liabilities in our balance sheet, and the changes in the net liability for the year ended December 31, were as follows:

	<u>2004</u>	<u>2003</u>
	(In millions)	
Net asset retirement liability at January 1	\$139	\$130
Liabilities settled	(19)	(22)
Accretion expense	15	17
Liabilities incurred	18	7
Changes in estimate	<u>12</u>	<u>7</u>
Net asset retirement liability at December 31	<u>\$165</u>	<u>\$139</u>

Our changes in estimate represent changes to the expected amount and timing of payments to settle our asset retirement obligations. These changes primarily result from obtaining new information about the timing

of our obligations to plug our natural gas and oil wells and the costs to do so. Had we adopted SFAS No. 143 as of January 1, 2002, our aggregate current and non-current retirement liabilities on that date would have been approximately \$113 million and our income from continuing operations and net income for the year ended December 31, 2002 would have been lower by \$11 million.

Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

In May 2003, the Financial Accounting Standards Board (FASB) issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*. This statement provides guidance on the classification of financial instruments as equity, as liabilities, or as both liabilities and equity. In particular, the standard requires that we classify all mandatorily redeemable securities as liabilities in the balance sheet. On July 1, 2003, we adopted the provisions of SFAS No. 150, and reclassified \$300 million of our Coastal Finance I preferred interests from preferred interests of consolidated subsidiaries to long-term financing obligations in our balance sheet. We also began classifying dividends accrued on these preferred interests as interest and debt expense in our income statement. These dividends were approximately \$26 million in both 2004 and 2003. These dividends were recorded in interest expense in 2004, and \$13 million of our 2003 dividends were recorded as interest expense and \$13 million were recorded as distributions on preferred interests in our income statement in 2003.

Accounting for Variable Interest Entities

In January 2003, the FASB issued Financial Interpretation (FIN) No. 46, *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51*. This interpretation defines a variable interest entity as a legal entity whose equity owners do not have sufficient equity at risk or a controlling financial interest in the entity. This standard requires a company to consolidate a variable interest entity if it is allocated a majority of the entity's losses or returns, including fees paid by the entity.

On January 1, 2004, we adopted this standard. Upon adoption, we consolidated Blue Lake Gas Storage Company, an equity investment that owns the Blue Lake natural gas storage facility. The impact of this consolidation was a net increase to property, plant and equipment of \$72 million, an increase to other current and non-current assets of \$6 million, an increase to third-party debt of \$14 million, an increase to other liabilities and equity of \$15 million, a decrease in our investment balance of \$30 million, and a decrease to notes receivable from affiliates of \$19 million.

Blue Lake Gas Storage owns and operates a 47 Bcf gas storage facility in Michigan. One of our subsidiaries operates the natural gas storage facility and we inject and withdraw all natural gas stored in the facility. We own a 75 percent equity interest in Blue Lake. This entity has \$8 million of third party debt as of December 31, 2004 that is non-recourse to us. We consolidated Blue Lake because we are allocated a majority of Blue Lake's losses and returns through our equity interest in Blue Lake.

We have significant interests in a number of variable interest entities. We were not required to consolidate these entities under FIN No. 46 and, as a result, our method of accounting for these entities did not change. As of December 31, 2004, these entities consisted primarily of 10 equity investments held in our Power segment that had interests in power generation and transmission facilities with a total generating capacity of approximately 2,900 gross MW. We operate many of these facilities but do not supply a significant portion of the fuel consumed or purchase a significant portion of the power generated by these facilities. The long-term debt issued by these entities is recourse only to the power project. As a result, our exposure to these entities is limited to our equity investments in and advances to the entities (\$501 million as of December 31, 2004) and our guarantees and other agreements associated with these entities (a maximum of \$42 million as of December 31, 2004).

New Accounting Pronouncements Issued But Not Yet Adopted

As of December 31, 2004, there were several accounting standards and interpretations that had not yet been adopted by us. Below is a discussion of significant standards that may impact us.

Accounting for Deferred Taxes on Foreign Earnings. In December 2004, the FASB issued FASB Staff Position (FSP) No. 109-2, *Accounting and Disclosure Guidance for the Foreign Earnings Repatriation*

Provision within the American Jobs Creation Act of 2004. FSP No. 109-2 clarified the existing accounting literature that requires companies to record deferred taxes on foreign earnings, unless they intend to indefinitely reinvest those earnings outside the U.S. This pronouncement will temporarily allow companies that are evaluating whether to repatriate foreign earnings under the American Jobs Creation Act of 2004 to delay recognizing any related taxes until that decision is made. This pronouncement also requires companies that are considering repatriating earnings to disclose the status of their evaluation and the potential amounts being considered for repatriation. The U.S. Treasury Department has not issued final guidelines for applying the repatriation provisions of the American Jobs Creation Act. We have not yet determined the potential range of our foreign earnings that could be impacted by this legislation and FSP No. 109-2, and we continue to evaluate whether we will repatriate any foreign earnings and the impact, if any, that this pronouncement will have on our financial statements.

Accounting for Asset Retirement Obligations. In March 2005, the FASB Issued FASB Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations*. FIN No. 47 requires companies to record a liability for those asset retirement obligations in which the timing or amount of settlement of the obligation are uncertain. These conditional obligations were not addressed by SFAS No. 143, which we adopted on January 1, 2003. FIN No. 47 requires that companies accrue this liability when a range of scenarios indicating the potential timing and settlement amounts of its conditional asset retirement obligations can be determined. We will adopt the provisions of this standard in the fourth quarter of 2005 and have not yet determined the impact, if any, that this pronouncement will have on our financial statements.

2. Divestitures

Sales of Assets and Investments

During 2004, 2003 and 2002, we completed and announced the sale of a number of assets and investments in each of our business segments. The following table summarizes the proceeds from these sales:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(In millions)		
<i>Regulated</i>			
Pipelines	\$ —	\$ 89	\$ 303
<i>Non-regulated</i>			
Production	24	137	1,248
Power	92	11	—
Field Services	3	94	120
<i>Other</i>			
Corporate	—	17	—
Total continuing ⁽¹⁾	<u>119</u>	<u>348</u>	<u>1,671</u>
Discontinued	<u>1,291</u>	<u>803</u>	<u>177</u>
Total	<u>\$1,410</u>	<u>\$1,151</u>	<u>\$1,848</u>

⁽¹⁾ Proceeds exclude returns of invested capital and cash transferred with the assets sold and include costs incurred in preparing assets for disposal. These items decreased our sales proceeds by \$32 million, \$35 million, and \$33 million for the years ended December 31, 2004, 2003 and 2002, respectively.

The following table summarizes the significant asset sales:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
Pipelines	<ul style="list-style-type: none"> • None 	<ul style="list-style-type: none"> • TX panhandle gathering system • 2.1% interest in Alliance pipeline • Sulfur extraction facility • Horsham pipeline in Australia 	<ul style="list-style-type: none"> • Natural gas and oil properties located in TX, KS, and OK • 12.3% equity interest in Alliance pipeline • Typhoon natural gas pipeline
Production	<ul style="list-style-type: none"> • Brazilian exploration and production acreage 	<ul style="list-style-type: none"> • Natural gas and oil properties in NM and the Gulf of Mexico • Drilling rigs 	<ul style="list-style-type: none"> • Natural gas and oil properties located in TX, CO and Utah
Power	<ul style="list-style-type: none"> • Utility Contract Funding • Mohawk River Funding IV • Interest in Bastrop Company 	<ul style="list-style-type: none"> • Mohawk River Funding I 	<ul style="list-style-type: none"> • None
Field Services	<ul style="list-style-type: none"> • Dauphin Island and Mobile Bay equity investments 	<ul style="list-style-type: none"> • Gathering systems located in WY • Midstream assets in the Mid-Continent regions 	<ul style="list-style-type: none"> • Dragon Trail gas processing plant • Gathering facilities in Utah
Corporate	<ul style="list-style-type: none"> • None 	<ul style="list-style-type: none"> • Aircraft 	<ul style="list-style-type: none"> • None
Discontinued	<ul style="list-style-type: none"> • Natural gas and oil production properties in Canada and other international production assets • Aruba and Eagle Point refineries and other petroleum assets 	<ul style="list-style-type: none"> • Corpus Christi refinery • Florida petroleum terminals • Louisiana lease crude • Coal reserves • Canadian natural gas and oil properties • Asphalt facilities 	<ul style="list-style-type: none"> • Coal reserves and properties and petroleum assets • Natural gas and oil properties located in Western Canada

See Note 3 and 16 for a discussion of gains, losses and asset impairments related to the sales above.

During 2005, we have either completed or announced the following sales:

- Interest in paraxylene plant for \$74 million;
- MTBE processing facility for \$5 million;
- Eagle Point power facility for \$3 million; and
- Interest in Rensselaer power facility and its obligations.

Under SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, we classify assets to be disposed of as held for sale or, if appropriate, discontinued operations when they have received

appropriate approvals by our management and/or El Paso's Board of Directors and when they meet other criteria. As of December 31, 2004, we had two domestic power plants in assets held for sale, which were impaired in previous years and which we expect to sell within the next twelve months. As of December 31, 2003, we had \$7 million of assets held for sale reflected in current assets on our balance sheet. Our assets held for sale as of December 31, 2003 related to domestic power assets in our Power segment that were approved by El Paso's Board of Directors for sale in 2003.

Discontinued Operations

International Natural Gas and Oil Production Operations. During 2004, our Canadian and certain other international natural gas and oil production operations were approved for sale. As of December 31, 2004, we have completed the sale of all of our Canadian operations and substantially all of our operations in Indonesia for total proceeds of approximately \$389 million. During 2004, we recognized approximately \$22 million in losses based on our decision to sell these assets. We expect to complete the sale of the remainder of these properties by mid-2005.

Petroleum Markets. During 2003, the sales of our petroleum markets businesses and operations were approved. These businesses and operations consisted of our Eagle Point and Aruba refineries, our asphalt business, our Florida terminal, tug and barge business, our lease crude operations, our Unilube blending operations, our domestic and international terminalling facilities and our petrochemical and chemical plants. Based on our intent to dispose of these operations, we were required to adjust these assets to their estimated fair value. As a result, we recognized pre-tax impairment charges during 2003 of approximately \$1.5 billion related to these assets. These impairments were based on a comparison of the carrying value of these assets to their estimated fair value, less selling costs. We also recorded realized gains of approximately \$59 million in 2003 from the sale of our Corpus Christi refinery, our asphalt assets, and our Florida terminalling and marine assets.

In 2004, we completed the sales of our Aruba and Eagle Point refineries for \$880 million and used a portion of the proceeds to repay approximately \$370 million of debt associated with the Aruba refinery. We recorded realized losses of approximately \$32 million in 2004, primarily from the sale of our Aruba and Eagle Point refineries. In addition, in 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing operations in our financial statements based on our decision to retain these operations. Our financial statements for all periods presented reflect this change.

Coal Mining. In 2002, our Board of Directors authorized the sale of our coal mining operations and we recorded an impairment of \$185 million. These operations consisted of fifteen active underground and two surface mines located in Kentucky, Virginia and West Virginia. The sale of these operations was completed in 2003 for \$92 million in cash and \$24 million in notes receivable, which were settled in the second quarter of 2004. We did not record a significant gain or loss on these sales.

The petroleum markets, coal mining and our other international natural gas and oil production operations discussed above are classified as discontinued operations in our financial statements for all of the historical periods presented. All of the assets and liabilities of these discontinued businesses are classified as current assets and liabilities as of December 31, 2004. The summarized financial results and financial position data of our discontinued operations were as follows:

	<u>Petroleum Markets</u>	<u>International Natural Gas and Oil Production Operations</u>	<u>Coal Mining</u>	<u>Total</u>
	(In millions)			
<i>Operating Results Data</i>				
Year Ended December 31, 2004 (Restated) ⁽¹⁾				
Revenues	\$ 787	\$ 31	\$ —	\$ 818
Costs and expenses	(839)	(52)	—	(891)
Loss on long-lived assets	(36)	(22)	—	(58)
Other income	13	—	—	13
Interest and debt expense	(2)	1	—	(1)
Loss before income taxes	(77)	(42)	—	(119)
Income taxes	2	(6)	—	(4)
Loss from discontinued operations, net of income taxes	<u>\$ (79)</u>	<u>\$ (36)</u>	<u>\$ —</u>	<u>\$ (115)</u>
Year Ended December 31, 2003 (Restated) ⁽¹⁾				
Revenues	\$ 5,652	\$ 88	\$ 27	\$ 5,767
Costs and expenses	(5,794)	(127)	(13)	(5,934)
Loss on long-lived assets	(1,404)	(89)	(9)	(1,502)
Other income (expenses)	(4)	—	1	(3)
Interest and debt expense	(11)	4	—	(7)
Income (loss) before income taxes	(1,561)	(124)	6	(1,679)
Income taxes	(263)	(135)	5	(393)
Income (loss) from discontinued operations, net of income taxes	<u>\$ (1,298)</u>	<u>\$ 11</u>	<u>\$ 1</u>	<u>\$ (1,286)</u>
Year Ended December 31, 2002				
Revenues	\$ 4,788	\$ 71	\$ 309	\$ 5,168
Costs and expenses	(4,916)	(148)	(327)	(5,391)
Loss on long-lived assets	(97)	(4)	(184)	(285)
Other income	20	—	5	25
Interest and debt expense	(12)	4	—	(8)
Loss before income taxes	(217)	(77)	(197)	(491)
Income taxes	16	(39)	(73)	(96)
Loss from discontinued operations, net of income taxes	<u>\$ (233)</u>	<u>\$ (38)</u>	<u>\$ (124)</u>	<u>\$ (395)</u>

(1) For 2004, amounts related to Petroleum Markets and International Natural Gas and Oil Production Operations were restated. For 2003, amounts related to International Natural Gas and Oil Production Operations were restated. See Note 1 to the consolidated financial statements for a further discussion of the restatements.

	<u>Petroleum Markets</u>	<u>International Natural Gas and Oil Production Operations</u>	<u>Total</u>
	(In millions)		
<i>Financial Position Data</i>			
December 31, 2004			
Assets of discontinued operations			
Accounts and notes receivables	\$ 39	\$ 2	\$ 41
Inventory	8	—	8
Other current assets	3	1	4
Property, plant and equipment, net	14	6	20
Other non-current assets	<u>33</u>	<u>—</u>	<u>33</u>
Total assets of discontinued operations	<u>\$ 97</u>	<u>\$ 9</u>	<u>\$ 106</u>
Liabilities of discontinued operations			
Accounts payable	\$ 5	\$ —	\$ 5
Other current liabilities	3	—	3
Other non-current liabilities	<u>3</u>	<u>—</u>	<u>3</u>
Total liabilities	<u>\$ 11</u>	<u>\$ —</u>	<u>\$ 11</u>
December 31, 2003			
Assets of discontinued operations			
Accounts and notes receivables	\$ 259	\$ 22	\$ 281
Inventory	385	3	388
Other current assets	131	8	139
Property, plant and equipment, net	521	399	920
Intangible assets, net	—	6	6
Other non-current assets	<u>70</u>	<u>—</u>	<u>70</u>
Total assets of discontinued operations	<u>\$1,366</u>	<u>\$438</u>	<u>\$1,804</u>
Liabilities of discontinued operations			
Accounts payable	\$ 172	\$ 38	\$ 210
Other current liabilities	86	—	86
Long-term debt	374	—	374
Other non-current liabilities	<u>26</u>	<u>3</u>	<u>29</u>
Total liabilities	<u>\$ 658</u>	<u>\$ 41</u>	<u>\$ 699</u>

3. Loss (Gain) on Long-Lived Assets

Loss (gain) on long-lived assets from continuing operations consists of realized gains and losses on sales of long-lived assets and impairments of long-lived assets including goodwill and other intangibles. During each of the three years ended December 31, our loss on long-lived assets were as follows:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(In millions)		
Net realized gain	<u>\$ (2)</u>	<u>\$(35)</u>	<u>\$(44)</u>
Asset impairments			
Power	103	28	18
Production	—	10	—
Field Services	5	4	14
Corporate	—	1	—
Total asset impairments	<u>108</u>	<u>43</u>	<u>32</u>
Loss (gain) on long-lived assets	106	8	(12)
Loss on investments in unconsolidated affiliates ⁽¹⁾	<u>292</u>	<u>128</u>	<u>47</u>
Loss on assets and investments	<u><u>\$398</u></u>	<u><u>\$136</u></u>	<u><u>\$ 35</u></u>

⁽¹⁾ See Note 16 for further description of these gains and losses.

Net Realized Gain

Our 2004 net realized gain was primarily related to the sale of assets within our Power segment.

Our 2003 net realized gain was primarily related to a \$19 million gain on the sales of our Mid-Continent midstream assets in our Field Services segment, a \$6 million gain on the sale of the Table Rock sulfur extraction facility in our Pipelines segment, a \$5 million gain on the sales of non-full cost pool assets in our Production segment and a \$5 million gain on the sales of other assets.

Our 2002 net gain was primarily related to \$35 million of net gains on the sales of our Natural Buttes and Ouray gathering systems and our Dragon Trail gas processing plant in our Field Services segment and \$10 million of other miscellaneous asset sales in our Pipelines segment. See Note 2 for a further discussion of these divestitures.

Asset Impairments

Our impairment charges for the years ended December 31, 2004, 2003 and 2002 were recorded primarily in connection with our intent to dispose of, or reduce our involvement in a number of assets, including charges of \$88 million in 2004 related to the planned sales of our domestic power contract restructuring assets.

For additional asset impairments on our discontinued operations and investments in unconsolidated affiliates, see Notes 2 and 16.

4. Ceiling Test Charges

During the year ended December 31, 2004, we had no ceiling test charges. During the years ended December 31, 2003 and 2002, we incurred ceiling test charges in the following full cost pools:

	<u>2003</u>	<u>2002</u>
	(In millions)	
U.S.	\$ 34	\$417
Brazil and Other International	<u>5</u>	<u>5</u>
Total	<u><u>\$ 39</u></u>	<u><u>\$422</u></u>

We use financial instruments to hedge against the volatility of natural gas and oil prices. The impact of qualifying cash flow hedges was considered in determining our ceiling test charges, and will be factored into future ceiling test calculations. The charges for our international cost pools would not have materially changed had the impact of our hedges not been included in calculating our ceiling test charges since we do not significantly hedge our international production activities. Had the impact of qualifying cash flow hedges been excluded from our U.S. full cost pool calculations, we would have incurred no ceiling test charges in 2004 or 2003, and would have incurred charges of \$576 million in 2002 compared with the charges we actually recorded.

5. Other Income and Other Expenses

The following are the components of other income and other expenses from continuing operations for each of the three years ended December 31:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(In millions)		
Other Income			
Interest income.....	\$ 13	\$ 17	\$13
Development, management and administrative services fees on power projects from affiliates.....	12	11	11
Allowance for funds used during construction	7	—	—
Re-application of SFAS No. 71 (CIG and WIC)	—	18	—
Favorable resolution of non-operating contingent obligations	—	8	31
Other	<u>12</u>	<u>12</u>	<u>15</u>
Total	<u>\$ 44</u>	<u>\$ 66</u>	<u>\$70</u>
Other Expenses			
Loss on early extinguishment of debt	\$ 10	\$ —	\$—
Minority interest in consolidated subsidiaries	1	(12)	52
Other	<u>3</u>	<u>7</u>	<u>18</u>
Total	<u>\$ 14</u>	<u>\$ (5)</u>	<u>\$70</u>

6. Income Taxes

Our pretax income (loss) from continuing operations is composed of the following for each of the three years ended December 31:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(In millions)		
U.S.	\$ 51	\$ 244	\$350
Foreign	<u>(80)</u>	<u>(2)</u>	<u>139</u>
	<u>\$ (29)</u>	<u>\$ 242</u>	<u>\$489</u>

The following table reflects the components of income taxes included in income (loss) from continuing operations for each of the three years ended December 31:

	<u>2004</u>	<u>2003</u> (In millions)	<u>2002</u>
Current			
Federal	\$11	\$ 68	\$(35)
State	44	14	2
Foreign	<u>—</u>	<u>—</u>	<u>5</u>
	55	82	(28)
Deferred			
Federal	6	(13)	137
State	(46)	(10)	33
Foreign	<u>(3)</u>	<u>(16)</u>	<u>1</u>
	<u>(43)</u>	<u>(39)</u>	<u>171</u>
Total income taxes	<u>\$12</u>	<u>\$ 43</u>	<u>\$143</u>

Our income taxes, included in income (loss) from continuing operations differ from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(In millions, except rates)		
Income taxes at the statutory federal rate of 35%	\$(10)	\$ 85	\$171
Increase (decrease)			
State income taxes, net of federal income tax effect	(2)	3	23
Foreign (income) loss taxed at different rates	36	8	(55)
Non-taxable stock dividends	—	(5)	(5)
Abandonments and sales of foreign investments	(7)	(25)	—
Valuation allowances	—	(21)	(3)
Dispositions of domestic assets	(7)	—	—
Other	<u>2</u>	<u>(2)</u>	<u>12</u>
Income taxes	<u>\$ 12</u>	<u>\$ 43</u>	<u>\$143</u>
Effective tax rate	<u>(41)%</u>	<u>18%</u>	<u>29%</u>

The following are the components of our net deferred tax liability related to continuing operations as of December 31:

	<u>2004</u> (Restated)	<u>2003</u> (Restated)
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	\$1,200	\$ 856
Investments in unconsolidated affiliates	103	302
Regulatory and other assets	<u>54</u>	<u>80</u>
Total deferred tax liability	<u>1,357</u>	<u>1,238</u>
Deferred tax assets		
Net operating loss and tax credit carryovers:		
U.S. federal	375	267
State	45	37
Foreign	29	7
Environmental liability	54	59
Price risk management activities	56	55
Allocated merger costs	106	107
Lease liabilities	30	2
Other	82	59
Valuation allowance	<u>(25)</u>	<u>(1)</u>
Total deferred tax asset	<u>752</u>	<u>592</u>
Net deferred tax liability	<u>\$ 605</u>	<u>\$ 646</u>

Historically, we have not recorded U.S. deferred tax liabilities on book versus tax basis differences in our Asian power investments because it was our intent to indefinitely reinvest the earnings from these projects outside the U.S. In 2004, our intent on these assets changed and we now intend to use the proceeds from the anticipated sale within the U.S. As a result, we recorded deferred tax liabilities which, as of December 31, 2004 were \$8 million, representing those instances where the book basis in our investments in the Asian power projects exceeded the tax basis. At this time, however, due to uncertainties as to the manner, timing and approval of the sales, we have not recorded deferred tax assets for those instances where the tax basis of our investments exceeded the book basis, except in instances where we believe the realization of the asset is assured. As of December 31, 2004, total deferred tax assets recorded on our Asian investments was \$6 million.

Cumulative undistributed earnings from the remainder of our foreign subsidiaries and foreign corporate joint ventures (excluding our Asian power assets discussed above) have been or are intended to be indefinitely reinvested in foreign operations. Therefore, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. At December 31, 2004, the portion of the cumulative undistributed earnings from these investments on which we have not recorded U.S. income taxes was approximately \$358 million. If a distribution of these earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustments recorded in accumulated other comprehensive income.

Under El Paso's tax accrual policy, we are allocated the tax effects associated with the sales of stock by employees under an employee stock purchase plan stock, the exercise of non-qualified stock options and the vesting of restricted stock, as well as restricted stock dividends. This allocation did not have a material effect in 2004, however, it increased taxes payable by \$4 million in 2003 and reduced taxes payable by \$2 million in 2002. These tax effects are included in additional paid-in capital in our balance sheets.

As of December 31, 2004, we have U.S. federal alternative minimum tax credits and general business credits of \$217 million that carryover indefinitely and capital loss carryovers of \$11 million for which the

carryover period ends in 2008. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2004.

	Carryover Period				Total
	2005	2006-2010	2011-2015	2016-2024 (Restated)	
	(In millions)				
U.S. federal net operating loss	\$ —	\$ —	\$ —	\$440	\$440
State net operating loss	3	287	31	229	550

We also have \$86 million of net foreign net operating loss carryovers that carryover indefinitely. Usage of our U.S. federal carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations.

We record a valuation allowance to reflect the estimated amount of deferred tax assets which we may not realize due to the uncertain availability of future taxable income or the expiration of net operating loss and tax credit carryovers. As of December 31, 2004, we maintained a valuation allowance of \$20 million related to state net operating loss carryovers and \$5 million related to foreign deferred tax assets for book impairments and ceiling test charges. As of December 31, 2003, we maintained a valuation allowance of \$1 million related to foreign deferred tax assets for ceiling charges. The change in our valuation allowances from December 31, 2003 to December 31, 2004 is primarily related to an additional valuation allowance for State of New Jersey legislation that limited use of state operating loss carryovers and an increase in valuation allowances related to foreign impairment of assets.

7. Fair Value of Financial Instruments

The following table presents the carrying amounts and estimated fair values of our financial instruments as of December 31:

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term financing obligations, including current maturities	\$3,757	\$3,931	\$5,321	\$5,233
Commodity-based price risk management derivatives	(148)	(148)	818	818

As of December 31, 2004 and 2003, the carrying amounts of cash and cash equivalents and trade receivables and payables represented fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market-based nature of the interest rate. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. See Note 8 for a discussion of our methodology of determining the fair value of the derivative instruments used in our price risk management activities.

8. Price Risk Management Activities

The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31, 2004 and 2003. In the table below, derivatives designated as hedges consist of instruments used to hedge our natural gas and oil production as well as instruments to hedge our interest rate risks on long-term debt. Derivatives from power contract restructuring activities relate to power purchase and sale agreements that arose from our activities in that business. The following table summarizes the carrying value of the derivatives used in our price risk management activities as of December 31:

	<u>2004</u>	<u>2003</u>
	(In millions)	
Net assets (liabilities)		
Derivatives designated as hedges	\$(148)	\$(124)
Derivatives from power contract restructuring activities ⁽¹⁾	<u>—</u>	<u>942</u>
Net assets (liabilities) from price risk management activities ⁽²⁾	<u>\$(148)</u>	<u>\$ 818</u>

⁽¹⁾ In 2004, we sold our subsidiaries that own these derivative contracts. See Note 2 for additional information on these sales.

⁽²⁾ Included in both current and non-current assets and liabilities on the balance sheet.

Our derivative contracts are recorded in our financial statements at fair value. The best indication of fair value is quoted market prices. However, when quoted market prices are not available, we estimate the fair value of those derivatives. Due to major industry participants exiting or reducing their trading activities in 2002 and 2003, the availability of reliable commodity pricing data from market-based sources that we used in estimating the fair value of our derivatives was significantly limited for certain locations and for longer time periods. For forward pricing data, we use commodity prices from market-based sources such as the New York Mercantile Exchange. We discount the estimated fair value of our derivatives using a LIBOR curve, except as described below for our restructured power contracts.

We record valuation adjustments to reflect uncertainties associated with the estimates we use in determining fair value. Common valuation adjustments include those for market liquidity and those for the credit-worthiness of our contractual counterparties. To the extent possible, we use market-based data together with quantitative methods to measure the risks for which we record valuation adjustments and to determine the level of these valuation adjustments.

The above valuation techniques are used for valuing derivative contracts that are used to hedge our natural gas production. We have adjusted this method to determine the fair value of our restructured power contracts. Our restructured power derivatives used the same methodology discussed above for determining the forward settlement prices but were discounted using a risk free interest rate, adjusted for the individual credit spread for each counterparty to the contract.

Derivatives Designated as Hedges

We engage in hedges of cash flow exposure primarily related to our natural gas and oil production activities. Hedges of cash flow exposure, which primarily relate to our natural gas hedges, are designed to hedge forecasted sales transactions or limit the variability of cash flows to be received or paid related to a recognized asset or liability. Changes in derivative fair values that are designated as cash flow hedges are deferred in accumulated other comprehensive income (loss) to the extent they are effective and are not included in income until the hedged transactions occur and are recognized in earnings. The ineffective portion of the hedge's change in value is recognized immediately in earnings as a component of operating revenues in our income statement.

We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. All hedging instruments are linked to the hedged asset, liability, firm commitment or forecasted transaction. We also assess whether these derivatives are highly effective in offsetting changes in cash flows or fair values of the hedged items. We discontinue hedge

accounting prospectively if we determine that a derivative is no longer highly effective as a hedge or if we decide to discontinue the hedging relationship.

A summary of the impacts of our cash flow hedges included in accumulated other comprehensive income (loss), net of income taxes, as of December 31, 2004 and 2003 follows:

	Accumulated Other Comprehensive Income (Loss)		Estimated Income (Loss) Reclassification in 2005 ⁽¹⁾	Final Termination Date
	2004	2003		
	(In millions)			
Held by consolidated entities	\$ 28	\$(49)	\$ 28	2005
Held by unconsolidated affiliates	18	13	9	2006
Undesignated ⁽²⁾	(113)	(25)	(113)	2005
Total ⁽³⁾	<u>\$(67)</u>	<u>\$(61)</u>	<u>\$ (76)</u>	

- ⁽¹⁾ Reclassifications occur upon the physical delivery of the hedge commodity and the corresponding expiration of the hedge.
⁽²⁾ In December 2004 and May 2002, we removed the hedging designation on these derivatives.
⁽³⁾ Accumulated other comprehensive income (loss) also includes \$(6) million and \$27 million of currency translation adjustments as of December 31, 2004 and 2003, as well as \$(20) million and \$(17) million of additional minimum pension liability, net of income taxes.

For the years ended December 31, 2004, 2003 and 2002, we recognized net losses of less than \$1 million, \$1 million and \$3 million, net of income taxes, in our income from continuing operations related to the ineffective portion of all cash flow hedges.

Power Contract Restructuring Activities

During 2001 and 2002, we conducted power contract restructuring activities that involved amending or terminating power purchase contracts at existing power facilities. In a restructuring transaction, we would eliminate the requirement that the plant provide power from its own generation to the customer of the contract (usually a regulated utility) and replace that requirement with a new contract that gave us the ability to provide power to the customer from the wholesale power market. In conjunction with these power restructuring activities, we generally entered into additional market-based contracts with El Paso Marketing to provide the power from the wholesale power market, which effectively “locked in” our margin on the restructured transaction as the difference between the contracted rate in the restructured sales contract and the wholesale market rates on the power purchase contract at the time.

Prior to a restructuring, the power plant and its related power purchase contract were accounted for at their historical cost, which was either the cost of construction or, if acquired, the acquisition cost. Revenues and expenses prior to the restructuring were, in most cases, accounted for on an accrual basis as power was generated and sold from the plant.

Following a restructuring, the accounting treatment for the power purchase agreement changed since the restructured contract met the definition of a derivative. In addition, since the power plant no longer had the exclusive obligation to provide power under the original, dedicated power purchase contract, it operated as a peaking merchant facility, generating power only when it was economical to do so. Because of this significant change in its use, the plant’s carrying value was typically written down to its estimated fair value. These changes also often required us to terminate or amend any related fuel supply and/or steam agreements, and enter into other third-party and intercompany contracts such as transportation agreements, associated with operating the merchant facility. Finally, in many cases power contract restructuring activities also involved contract terminations that resulted in cash payments by the customer to cancel the underlying dedicated power contract.

In 2002, we completed a power contract restructuring on our consolidated Eagle Point power facility and applied the accounting described above to that transaction. We also employed the principles of our power contract restructuring business in reaching a settlement of a dispute under our Nejapa power contract which

included a cash payment to us. We recorded these payments as operating revenues in our Power segment. For the year ended December 31, 2002, our consolidated power restructuring activities had the following effects on our consolidated financial statements:

	Assets from Price Risk Management Activities	Liabilities from Price Risk Management Activities	Property, Plant and Equipment and Intangible Assets	Operating Revenues	Operating Expenses	Increase (Decrease) in Minority Interest ⁽¹⁾
	(In millions)					
Initial gain on restructured contracts	\$978	\$ 80	\$ —	\$ 988	—	\$ 172
Write-down of power plants and intangibles and other fees	—	—	(328)	—	489	(109)
Change in value of restructured contracts during 2002	8	—	—	(96)	—	(20)
Change in value of third-party wholesale power supply contracts	—	(62)	—	62	—	(3)
Purchase of power under power supply contracts	—	—	—	—	47	(11)
Sale of power under restructured contracts	—	—	—	111	—	28
Total	<u>\$986</u>	<u>\$ 18</u>	<u>\$(328)</u>	<u>\$1,065</u>	<u>\$536</u>	<u>\$ 57</u>

⁽¹⁾ In our restructuring activities, third-party owners also held ownership interests in the plants and were allocated a portion of the income or loss.

As a result of El Paso's credit downgrade and economic changes in the power market, we are no longer pursuing additional power contract restructuring activities and have sold our remaining restructured power contracts in 2004, completing the sales of UCF (which is the restructured Eagle Point power contract) and Mohawk River Funding IV. (See Note 2 for a discussion of these sales.)

9. Inventory

We have the following inventory as of December 31:

	2004	2003
	(In millions)	
Materials and supplies and other	\$40	\$52
Natural gas and NGL in storage	18	3
Total inventory	<u>\$58</u>	<u>\$55</u>

10. Regulatory Assets and Liabilities

Our regulatory assets and liabilities are included in other current and non-current assets and liabilities in our balance sheets. These balances are presented in our balance sheets on a gross basis. Below are the details as of December 31, of our regulatory assets and liabilities for our regulated interstate systems that apply the provisions of SFAS No. 71, which are recoverable over various periods:

	<u>2004</u>	<u>2003</u>
	(In millions)	
Non-current regulatory assets		
Grossed-up deferred taxes on capitalized funds used during construction ⁽¹⁾	\$15	\$12
Postretirement benefits ⁽¹⁾	6	6
Under-collected federal income taxes ⁽¹⁾	<u>2</u>	<u>2</u>
Total regulatory assets	<u>\$23</u>	<u>\$20</u>
Current regulatory liabilities		
Postretirement benefits ⁽¹⁾	<u>\$—</u>	\$ 1
Non-current regulatory liabilities		
Excess deferred federal income taxes	6	4
Over-collected fuel obligation	<u>11</u>	<u>5</u>
Total non-current regulatory liabilities	<u>17</u>	<u>9</u>
Total regulatory liabilities	<u>\$17</u>	<u>\$10</u>

⁽¹⁾ Some of these amounts are not included in our rate base on which we earn a current return.

11. Property, Plant and Equipment

At December 31, 2004 and 2003, we had approximately \$280 million and \$363 million of construction work-in-progress included in our property, plant and equipment.

As of December 31, 2004 and 2003, ANR has excess purchase costs associated with its acquisition. Total excess costs on this pipeline were approximately \$2 billion. These excess costs are being amortized over the life of the related pipeline assets, and our amortization expense during each of the three years ended December 31, 2004, 2003 and 2002 was approximately \$34 million. We do not currently earn a return on these excess purchase costs from our rate payers.

12. Debt, Other Financing Obligations and Other Credit Facilities

Our long-term financing obligations outstanding consisted of the following as of December 31:

	<u>2004</u>	<u>2003</u>
	(In millions)	
Long-term debt		
El Paso CGP Company		
Senior notes, 6.2% through 7.75%, due 2004 through 2010	\$ 930	\$1,305
Senior debentures, 6.375% through 10.75%, due 2004 through 2037	1,357	1,395
Power		
Non-recourse senior notes, 7.75% and 7.944%, due 2008 and 2016	—	904
Recourse notes 8.5%, due 2005	37	81
El Paso Production Company		
Floating rate notes, due 2005 and 2006	—	200
ANR Pipeline		
Debentures and senior notes, 7.0% through 9.625%, due 2010 through 2025	800	800
Notes, 13.75% due 2010	12	13
Colorado Interstate Gas		
Debentures, 6.85% and 10.0%, due 2037 and 2005	280	280
Other	48	51
Subtotal	<u>3,464</u>	<u>5,029</u>
Other financing obligations		
Coastal Finance I	300	300
	3,764	5,329
Less:		
Unamortized discount on long-term debt	7	8
Current maturities of long-term debt	310	310
Total long-term financing obligations, less current maturities	<u>\$3,447</u>	<u>\$5,011</u>

During 2004 and to date in 2005, we had the following changes in our debt financing obligations:

<u>Company</u>	<u>Type</u>	<u>Interest Rate</u>	<u>Principal</u> (In millions)	<u>Due Date</u>
<i>Issuances and other increases</i>				
Blue Lake Gas Storage ⁽¹⁾	Non-recourse term loan	LIBOR + 1.2%	\$ 14	2006
	Increase through December 31, 2004.....		14	
Colorado Interstate Gas Company	Senior Notes	5.95%	200	2015
	Increase through date of filing		\$ 214	
<i>Repayments, repurchases and other retirements</i>				
El Paso CGP	Note	LIBOR + 3.5%	\$ 200	
El Paso CGP	Note	6.2%	190	
Mohawk River Funding IV ⁽²⁾	Non-recourse note	7.75%	72	
UCF ⁽²⁾	Non-recourse senior notes	7.944%	815	
El Paso CGP	Notes	Various	185	
El Paso CGP	Senior Debentures	10.25%	38	
Other	Long-term debt	Various	79	
	Decreases through December 31, 2004		1,579	
Other	Long-term debt	Various	42	
	Decreases through date of filing		\$1,621	

⁽¹⁾ This debt was consolidated as a result of adopting FIN No. 46 (see Note 1).

⁽²⁾ The remaining balance of these debt obligations was eliminated when we sold our interests in Mohawk River Funding IV and UCF.

Aggregate scheduled maturities of the principal amounts of long-term financing obligations for the next 5 years and in total thereafter are as follows (in millions):

2005	\$ 310
2006	330
2007	8
2008	416
2009	201
Thereafter	<u>2,499</u>
Total long-term financing obligations, including current maturities	<u>\$3,764</u>

Included above in 2005 is \$75 million of debentures that holders have the option to redeem on June 1, 2005, prior to their stated maturities. This \$75 million is eligible for redemption solely on June 1, 2005 and, if not redeemed, will be reclassified to long-term debt in the second quarter of 2005. Included in the “thereafter” line of the table above are \$300 million of debentures that holders have an option to redeem in 2007 prior to their stated maturity.

Credit Facilities

In November 2004, El Paso replaced its previous \$3 billion revolving credit facility, which was scheduled to mature in June 2005, with a new \$3 billion credit agreement with a group of lenders. Certain of our subsidiaries, ANR and CIG, continue to be eligible borrowers under the new credit agreement. Additionally, El Paso and certain of its subsidiaries have guaranteed borrowings under the new credit agreement, which is collateralized by our interests in ANR, CIG, WIC, and ANR Storage Company.

As of December 31, 2004, under El Paso’s \$3 billion credit agreement, El Paso had \$1.25 billion outstanding under the term loan and had utilized approximately all of the \$750 million letter of credit facility and approximately \$0.4 billion of the \$1 billion revolving credit facility to issue letters of credit, none of which was borrowed or issued on behalf of ANR or CIG.

Restrictive Covenants

Our restrictive covenants include restrictions on liens securing debt and guarantees, restrictions on mergers and on the sales of assets, and cross-acceleration provisions.

Some of our subsidiaries are subject to a number of additional restrictions and covenants. These restrictions and covenants include limitations of additional debt at some of our subsidiaries; limitations on the use of proceeds from borrowing at some of our subsidiaries; limitations, in some cases, on transactions with our affiliates; limitations on the occurrence of liens; potential limitations on the abilities of some of our subsidiaries to declare and pay dividends and potential limitations on some of our subsidiaries to participate in cash management programs and limitations on our ability to prepay debt. A breach of any of these covenants could result in acceleration of our debt and other financial obligations and that of our subsidiaries.

In addition, our indentures associated with our public debt contain \$5 million cross-acceleration provisions. These indentures state that should an event of default occur resulting in the acceleration of other debt obligations of us or our significant subsidiaries (as defined in the agreements) in excess of \$5 million, the long-term debt obligations containing such provisions could be accelerated. The acceleration of our's and El Paso's debt would adversely affect our liquidity position and in turn, our financial condition.

Other Financing Arrangements

Coastal Finance I. Coastal Finance I is a wholly owned business trust formed in May 1998. Coastal Finance I completed a public offering of 12 million mandatory redemption preferred securities for \$300 million. Coastal Finance I holds subordinated debt securities issued by us that it purchased with the proceeds of the preferred securities offering. Cumulative quarterly distributions are being paid on the preferred securities at an annual rate of 8.375 percent of the liquidation amount of \$25 per preferred security. Coastal Finance I's only source of income is interest earned on these subordinated debt securities. This interest income is used to pay the obligations on Coastal Finance I's preferred securities. The preferred securities are mandatorily redeemable on the maturity date, June 30, 2038, and may be redeemed at our option on or after May 13, 2003. The redemption price to be paid is \$25 per preferred security, plus accrued and unpaid distributions to the date of redemption. We provide a guarantee of the payment of obligations of Coastal Finance I related to its preferred securities to the extent Coastal Finance I has funds available. During 2003, the amounts outstanding of these securities were reclassified as long-term debt from preferred interests in our subsidiaries as a result of a new accounting standard.

Non-Recourse Project Financings. Many of our power subsidiaries and investments have borrowed a material portion of the costs to acquire or construct assets. Such borrowings are made with recourse only to the project company and assets (i.e. without recourse to us). On occasion, events have occurred in connection with several of our projects that have either constituted an event of default under the loan agreements or could constitute an event of default upon delivery of a notice from the lenders and the failure of the subsidiary or investee to cure the event during an applicable grace period. We have several projects that we account for as equity investments that are in default under their loan agreements, including Saba. We have a \$9 million interest in Saba. There is no recourse to us under the loans at these investments. In addition, we have had events of default or other events that could lead to an event of default upon notice from the lenders on other projects, but we do not believe any of these defaults will have a material impact on our or our subsidiaries' financial statements.

13. Commitments and Contingencies

Legal Proceedings

Grynberg. A number of our subsidiaries were named defendants in actions filed in 1997 brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. The plaintiff in this case seeks royalties that he contends the government should have received had the volume and

heating value been differently measured, analyzed, calculated and reported, together with interest, treble damages, civil penalties, expenses and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes (*In re: Natural Gas Royalties Qui Tam Litigation*, U.S. District Court for the District of Wyoming, filed June 1997). Motions to dismiss have been filed on behalf of all defendants. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

Will Price (formerly Quinque). A number of our subsidiaries are named as defendants in *Will Price, et al. v. Gas Pipelines and Their Predecessors, et al.*, filed in 1999 in the District Court of Stevens County, Kansas. Plaintiffs allege that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands and seek to recover royalties that they contend they should have received had the volume and heating value of natural gas produced from their properties been differently measured, analyzed, calculated and reported, together with prejudgment and postjudgment interest, punitive damages, treble damages, attorneys' fees, costs and expenses, and future injunctive relief to require the defendants to adopt allegedly appropriate gas measurement practices. No monetary relief has been specified in this case. Plaintiffs' motion for class certification of a nationwide class of natural gas working interest owners and natural gas royalty owners was denied on April 10, 2003. Plaintiffs' were granted leave to file a Fourth Amended Petition, which narrows the proposed class to royalty owners in wells in Kansas, Wyoming and Colorado and removes claims as to heating content. A second class action has since been filed as to the heating content claims. The plaintiffs have filed motions for class certification in both proceedings and the defendants have filed briefs in opposition thereto. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

MTBE. In compliance with the 1990 amendments to the Clean Air Act, we use the gasoline additive, methyl tertiary-butyl ether (MTBE), in some of our gasoline. We have also produced, bought, sold and distributed MTBE. A number of lawsuits have been filed throughout the U.S. regarding MTBE's potential impact on water supplies. We and some of our subsidiaries are among the defendants in over 60 such lawsuits. As a result of a ruling issued on March 16, 2004, these suits have been or are in the process of being consolidated for pre-trial purposes in multi-district litigation in the U.S. District Court for the Southern District of New York. The plaintiffs, certain state attorneys general and various water districts seek remediation of their groundwater, prevention of future contamination, a variety of compensatory damages, punitive damages, attorney's fees, and court costs. Our costs and legal exposure related to these lawsuits are not currently determinable.

Reserves. We have been named as a defendant in a purported class action claim styled, *GlickenHaus & Co. et. al. v. El Paso Corporation, El Paso CGP Company, et. al.*, filed in April 2004 in federal court in Houston. The plaintiffs have additionally sued several individuals. The plaintiffs generally allege that our reporting of oil and gas reserves was materially false and misleading between February 2000 and February 2004. This lawsuit has been consolidated with other purported securities class action lawsuits in *Oscar S. Wyatt et. al. v. El Paso Corporation et. al.* pending in federal court in Houston. Our costs and legal exposure related to this lawsuit and claims are not currently determinable.

Governmental Investigations

Governmental and Other Reviews. In October 2003, El Paso announced that the SEC had authorized the Staff of the Fort Worth Regional Office to conduct an investigation of certain aspects of our periodic reports filed with the SEC. The investigation appears to be focused principally on our power plant contract restructurings and the related disclosures and accounting treatment for the restructured power contracts, including in particular the Eagle Point restructuring transaction completed in 2002. We are cooperating with the SEC investigation.

Reserve Revisions. In March 2004, El Paso received a subpoena from the SEC requesting documents relating to its December 31, 2003 natural gas and oil reserve revisions. El Paso and its Audit Committee have also received federal grand jury subpoenas for documents regarding the reserve revision. We are assisting

El Paso and its Audit Committee in their efforts to cooperate with the SEC and the U.S. Attorney investigations into the matter.

Storage Reporting. In November 2004, ANR received a data request from the FERC in connection with its investigation into the weekly storage withdrawal number reported by the Energy Information Administration (EIA) for the eastern region on November 24, 2004, that was subsequently revised downward by the EIA. Specifically, ANR provided information on its weekly EIA submissions for the weeks ending November 12, 2004 and November 19, 2004, ANR's submissions to the EIA were not revised subsequent to their original submissions. Although ANR made a correction to one daily posting on its electronic bulletin board during this period, those postings are unrelated to EIA submissions. In December 2004, ANR received a similar data request from the CFTC and ANR provided the requested information. On December 17, 2004, the FERC held a press conference at which they disclosed that their inquiry has determined that an unaffiliated third party was the source of the downward revision.

Iraq Oil Sales. In September 2004, we received a subpoena from the grand jury of the U.S. District Court for the Southern District of New York to produce records regarding the United Nation's Oil for Food Program governing sales of Iraqi oil. The subpoena seeks various records relating to transactions in oil of Iraqi origin during the period from 1995 to 2003. In November 2004, we received an order from the SEC to provide a written statement and to produce certain documents in connection with the Oil for Food Program. We have also received informal requests for information and documents from the United States Senate's Permanent Subcommittee of Investigations and the House of Representatives International Relations Committee related to our purchases of Iraqi crude under the Oil for Food Program. We are cooperating with the U.S. Attorney's, the SEC's, Senate Subcommittee's and the House Committee's investigations of this matter.

In addition to the above matters, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation, none of which we believe will have a material impact on us.

For each of our outstanding legal and other contingent matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of these matters cannot be predicted with certainty and there are still uncertainties related to these costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. However, it is possible that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accounts accordingly. As of December 31, 2004, we had approximately \$36 million accrued for all outstanding legal matters and other contingencies.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2004, we had accrued approximately \$128 million, including approximately \$126 million for expected remediation costs and associated onsite, offsite and groundwater technical studies and approximately \$2 million for related environmental legal costs, which we anticipate incurring through 2027. Of the \$128 million accrual, \$44 million was reserved for facilities we currently operate, and \$84 million was reserved for non-operating sites (facilities that are shut down or have been sold) and Superfund sites.

Our reserve estimates range from approximately \$128 million to approximately \$199 million. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued (\$38 million). Second, where the most likely outcome cannot be estimated, a range of costs is established (\$90 million to \$161 million), and if no one amount in that

range is more likely than any other, the lower end of the range has been accrued. By type of site, our reserves are based on the following estimates of reasonably possible outcomes.

<u>Sites</u>	<u>December 31, 2004</u>	
	<u>Expected</u>	<u>High</u>
	(In millions)	
Operating	\$ 44	\$ 49
Non-operating	80	141
Superfund	<u>4</u>	<u>9</u>
Total	<u>\$128</u>	<u>\$199</u>

Below is a reconciliation of our accrued liability from January 1, 2004 to December 31, 2004 (in millions):

Balance as of January 1, 2004	\$131
Additions/adjustments for remediation activities	9
Payments for remediation activities	(18)
Other changes, net	<u>6</u>
Balance as of December 31, 2004	<u>\$128</u>

For 2005, we estimate that our total remediation expenditures will be approximately \$31 million. In addition, we expect to make capital expenditures for environmental matters of approximately \$24 million in the aggregate for the years 2005 through 2009. These expenditures primarily relate to compliance with clean air regulations.

CERCLA Matters. We have received notice that we could be designated, or have been asked for information to determine whether we could be designated, as a Potentially Responsible Party (PRP) with respect to 27 active sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) or state equivalents. We have sought to resolve our liability as a PRP at these sites through indemnification by third-parties and settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2004, we have estimated our share of the remediation costs at these sites to be between \$4 million and \$9 million. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these issues are included in the previously indicated estimates for Superfund sites.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current environmental reserves are adequate.

Rates and Regulatory Matters

Pipeline Integrity Costs. In November 2004, the FERC issued a proposed accounting release that may impact certain costs our interstate pipelines incur related to their pipeline integrity programs. If the release is enacted as written, we would be required to expense certain future pipeline integrity costs instead of capitalizing them as part of our property, plant and equipment. Although we continue to evaluate the impact

of this potential accounting release, we currently estimate that if the release is enacted as written, we would be required to expense an additional amount of pipeline integrity expenditures in the range of approximately \$6 million to \$12 million annually over the next eight years.

Inquiry Regarding Income Tax Allowances. In December 2004, the Federal Energy Regulatory Commission (FERC) issued a Notice of Inquiry (NOI) in response to a recent D.C. Circuit decision that held the FERC had not adequately justified its policy of providing a certain oil pipeline limited partnership with an income tax allowance equal to the proportion of its limited partnership interests owned by corporate partners. The FERC sought comments on whether the court's reasoning should be applied to other partnerships or other ownership structures. We own interests in non-taxable entities that could be affected by this ruling. We cannot predict what impact this inquiry will have on our interstate pipelines, including those pipelines that are not owned by a corporate entity, such as Great Lakes Gas Transmission Limited Partnership which is jointly owned with unaffiliated parties.

Selective Discounting Notice of Inquiry. In November 2004, the FERC issued a NOI seeking comments on its policy regarding selective discounting by natural gas pipelines. The FERC seeks comments regarding whether its practice of permitting pipelines to adjust their ratemaking throughput downward in rate cases to reflect discounts given by pipelines for competitive reasons is appropriate when the discount is given to meet competition from another natural gas pipeline. Our pipelines filed comments on the NOI. Neither the final outcome of this inquiry nor the impact on our pipelines can be predicted with certainty.

Commitments and Purchase Obligations

Operating Leases. We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and operating facilities and office and operating equipment, and the terms of the agreements vary from 2005 until 2031. As of December 31, 2004, our total commitments under operating leases were approximately \$148 million. Minimum annual rental commitments under our operating leases at December 31, 2004, were as follows:

<u>Year Ending December 31,</u>	<u>Operating Leases⁽¹⁾ (In millions)</u>
2005	\$ 30
2006	18
2007	15
2008	14
2009	14
Thereafter	<u>57</u>
Total	<u>\$148</u>

⁽¹⁾ These amounts exclude our proportional share of minimum annual rental commitments paid by El Paso, which are allocated to us through an overhead allocation.

Rental expense on our operating leases for the years ended December 31, 2004, 2003 and 2002 was \$69 million, \$67 million and \$56 million. These amounts include our share of the overhead allocation from El Paso.

Guarantees. We are involved in various joint ventures and other ownership arrangements that sometimes require additional financial support that results in the issuance of financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. As of December 31, 2004, we had approximately \$10 million of both financial and performance guarantees, not otherwise reflected in our financial statements. These guarantees are related to our domestic and international power operations.

Other Commercial Commitments. We have various other commercial commitments and purchase obligations that are not recorded on our balance sheet. At December 31, 2004, we had firm commitments under transportation contracts of \$6 million and other purchase and capital commitments (including maintenance, engineering, procurement and construction contracts) of \$133 million. Included in other purchase and capital commitments above at December 31, 2004, are unconditional purchase obligations entered into by our pipelines for products and services totaling \$113 million for 2005.

14. Retirement Benefits

Pension and Retirement Benefits

El Paso maintains a pension plan that covers substantially all of its U.S. employees, including our employees except for employees of our former coal operations who are covered under a separate plan.

Prior to our merger with El Paso, we maintained defined benefit plans. Our pension plans covered substantially all of our U.S. employees. On April 1, 2001, our primary pension plan was merged into El Paso's existing cash balance plan. Our employees who were participants in our primary plan on March 31, 2001 receive the greater of cash balance benefits or our plan benefits accrued through March 31, 2006.

We continue to maintain another pension plan that is closed to new participants and provides benefits to former employees of our previously discontinued coal operations. El Paso anticipates that contributions to this pension plan will be less than \$1 million in 2005.

El Paso also maintains a defined contribution retirement savings plan covering its U.S. employees, including our employees. Prior to May 1, 2002, El Paso matched 75 percent of participant basic contributions up to 6 percent, with the matching contribution being made to the plan's stock fund which participants could diversify at any time. After May 1, 2002, the plan was amended to allow for company matching contributions to be invested in the same manner as that of participant contributions. Effective March 1, 2003, El Paso suspended the matching contribution, but reinstated it again at a rate of 50 percent of participant basic contributions up to 6 percent on July 1, 2003. Effective July 1, 2004, El Paso increased the matching contribution to 75 percent of participant basic contributions up to 6 percent.

El Paso is responsible for benefits accrued under its pension, other postretirement and retirement savings plans and allocates the related costs to its affiliates.

Below is the change in projected benefit obligation, change in plan assets and reconciliation of funded status for our pension and other postretirement benefit plans. Our benefits are presented and computed as of and for the twelve months ended September 30.

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	2004	2003
	(In millions)			
Change in benefit obligation:				
Projected benefit obligation at beginning of period	\$ 81	\$ 79	\$100	\$102
Service cost	—	2	—	—
Interest cost	5	4	6	6
Participant contributions	—	—	5	5
Curtailment and special termination benefit	—	(8)	—	(6)
Actuarial loss (gain)	7	7	(1)	10
Projected benefits paid	(4)	(3)	(15)	(17)
Projected benefit obligation at end of period	<u>\$ 89</u>	<u>\$ 81</u>	<u>\$ 95</u>	<u>\$100</u>

	Pension Benefits		Other Postretirement Benefits	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
	(In millions)			
Change in plan assets:				
Fair value of plan assets at beginning of period	\$ 63	\$ 59	\$ 59	\$ 46
Actual return on plan assets	7	7	5	8
Employer contributions	—	—	17	17
Participant contributions	—	—	5	5
Projected benefits paid	<u>(4)</u>	<u>(3)</u>	<u>(15)</u>	<u>(17)</u>
Fair value of plan assets at end of period	<u>\$ 66</u>	<u>\$ 63</u>	<u>\$ 71</u>	<u>\$ 59</u>
Reconciliation of funded status:				
Fair value of plan assets at September 30	\$ 66	\$ 63	\$ 71	\$ 59
Less: Projected benefit obligation at end of period	<u>89</u>	<u>81</u>	<u>95</u>	<u>100</u>
Funded status at September 30	(23)	(18)	(24)	(41)
Fourth quarter contributions and income	—	—	3	4
Unrecognized net actuarial loss (gain)	<u>30</u>	<u>25</u>	<u>(27)</u>	<u>(24)</u>
Prepaid (accrued) benefit cost at December 31,	<u>\$ 7</u>	<u>\$ 7</u>	<u>\$(48)</u>	<u>\$(61)</u>

	Pension Benefits	
	<u>2004</u>	<u>2003</u>
	(In millions)	
Amounts recognized in the statement of financial position consist of:		
Accrued benefit liability	\$(23)	\$(18)
Accumulated other comprehensive loss	<u>30</u>	<u>25</u>
Net amount recognized at year-end	<u>\$ 7</u>	<u>\$ 7</u>

Below is information for our pension plans that have accumulated benefit obligations in excess of plan assets for the year ended December 31:

	<u>2004</u>	<u>2003</u>
	(In millions)	
Projected benefit obligation	\$89	\$81
Accumulated benefit obligation	89	81
Fair value of plan assets	66	63

Future benefits expected to be paid from our pension plans and our other postretirement plans as of December 31, 2004, were as follows:

<u>Year Ending December 31,</u>	<u>Pension Benefits</u>	<u>Other Postretirement Benefits⁽¹⁾</u>
	(In millions)	
2005	\$ 4	\$10
2006	4	9
2007	4	9
2008	4	9
2009	4	8
2010-2014	<u>24</u>	<u>40</u>
Total	<u>\$44</u>	<u>\$85</u>

⁽¹⁾ Includes a reduction of less than \$1 million in each year for an expected subsidy related to the Medicare Prescription Drug, Improvement, and Modernization Act of 2003.

For each of the years ended December 31, the components of net benefit cost (income) are as follows:

	<u>Pension Benefits</u>			<u>Other Postretirement Benefits</u>		
	<u>Year Ended December 31,</u>					
	<u>2004</u>	<u>2003</u>	<u>2002</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(In millions)					
Service cost	\$—	\$ 2	\$ 3	\$—	\$—	\$ 1
Interest cost	5	5	5	6	6	8
Expected return on plan assets	(5)	(6)	(7)	(3)	(2)	(2)
Amortization of net actuarial loss	—	—	—	(1)	(1)	(1)
Curtailment and special termination benefits ..	—	<u>1</u>	—	—	<u>(6)</u>	—
Net benefit cost (income)	<u>\$—</u>	<u>\$ 2</u>	<u>\$ 1</u>	<u>\$ 2</u>	<u>\$(3)</u>	<u>\$ 6</u>

We are required to recognize an additional minimum liability for pension plans with an accumulated benefit obligation in excess of plan assets. We recorded an other comprehensive loss of \$5 million in 2004 and \$6 million in 2003 related to the change in this additional minimum liability.

Projected benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining the projected benefit obligation and net benefit cost of our pension and other postretirement plans for 2004, 2003 and 2002:

	<u>Pension Benefits</u>			<u>Other Postretirement Benefits</u>		
	<u>2004</u>	<u>2003</u>	<u>2002</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(Percent)			(Percent)		
Assumptions related to benefit obligations at September 30:						
Discount rate	5.75	6.00		5.75	6.00	
Assumptions related to benefit costs for the year ended December 31:						
Discount rate	6.00	6.75	7.25	6.00	6.75	7.25
Expected return on plan assets ⁽¹⁾	8.50	8.80	8.80	7.50	7.50	7.50
Rate of compensation increase	— ⁽²⁾	4.00	4.00			

⁽¹⁾ The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 35 percent to 39 percent on other postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on our target asset allocations of our investment portfolio. For 2005, the assumed expected return on assets for pension benefits will be reduced to 8 percent.

⁽²⁾ In 2003, our pension plan was closed to new participants and, as a result, it provides benefits solely to former employees.

Actuarial estimates for our other postretirement benefits plans assumed a weighted-average annual rate of increase in the per capita costs of covered health care benefits of 10.0 percent in 2004, gradually decreasing to 5.5 percent by the year 2009. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point increase (decrease) in assumed health care cost trends would have increased (decreased) our accumulated postretirement obligation by \$3 million and would not have significantly impacted our service cost or interest cost as of and for the periods ended September 30, 2004 and 2003.

Plan Assets

The following table provides the target and actual asset allocations in our pension and other postretirement benefit plans as of September 30:

<u>Asset Category</u>	<u>Pension Plans</u>			<u>Other Postretirement Plans</u>		
	<u>Target</u>	<u>Actual 2004</u>	<u>Actual 2003</u>	<u>Target</u>	<u>Actual 2004</u>	<u>Actual 2003</u>
		(Percent)			(Percent)	
Equity securities ⁽¹⁾	60	62	70	65	58	28
Debt securities	40	37	29	35	32	58
Other	—	1	1	—	10	14
Total	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>	<u>100</u>

⁽¹⁾ Actuals for our pension plans include \$2 million (3 percent of total assets) and \$1 million (2.1 percent of total assets) of El Paso's common stock at September 30, 2004 and September 30, 2003.

The primary investment objective of our plans is to ensure, that over the long-term life of the plans, an adequate pool of sufficiently liquid assets to support the benefit obligations to participants, retirees and beneficiaries exists. In meeting this objective, the plans seek to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall of investment performance compared to investment objectives is the result of general economic and capital market conditions.

In 2003, we modified our target asset allocations for our other postretirement benefit plans to increase our equity allocation to 65 percent of total plan assets and as a result, the actual assets as of September 30, 2004 were close to our target. During 2004, we modified our target and actual asset allocations for our pension plans to reduce our equity allocation to 60 percent of total plan assets. Correspondingly, our 2005 assumption related to the expected return on plan assets was reduced from 8.5% to 8.0% to reflect this change.

15. Business Segment Information

During 2004, we reorganized our business structure into two primary business lines, regulated and non-regulated, and modified our operating segments. Historically, our operating segments included Pipelines, Production, Merchant Energy and Field Services. As a result of this reorganization, we eliminated our Merchant Energy segment and established an individual Power segment. All periods presented reflect this change in segments. Our regulated business consists of our Pipelines segment, while our non-regulated businesses consist of our Production, Power, and Field Services segments. Our segments are strategic business units that provide a variety of energy products and services. They are managed separately as each segment requires different technology and marketing strategies. Our corporate operations include our general and administrative functions as well as various other contracts and assets, all of which are immaterial.

During the first quarter of 2004, we reclassified our petroleum ship charter operations from discontinued operations to continuing corporate operations. During the second quarter of 2004, we reclassified our Canadian and certain other international natural gas and oil production operations from our Production segment to discontinued operations. Our operating results for all periods presented reflect these changes.

Our Pipelines segment provides natural gas transmission, storage, and related services, primarily in the United States. We conduct our activities primarily through four wholly owned transmission systems and a partially owned interstate transmission system along with four underground natural gas storage entities.

Our Production segment is engaged in the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids, primarily in the United States and Brazil. In the United States, Production has onshore operations and properties primarily in Texas, Utah, West Virginia and Wyoming and offshore operations and properties in federal and state waters in the Gulf of Mexico.

Our Power segment owns and has interests in domestic and international power assets. As of December 31, 2004, our power segment primarily consisted of an international power business. Historically, this segment also had domestic power plant operations and a domestic power contract restructuring business. We have sold or announced the sale of substantially all of these domestic businesses.

Our Field Services segment conducts midstream activities related to our remaining gathering and processing assets.

We had no customers whose revenues exceeded 10 percent of our total revenues in 2004, 2003 and 2002.

We use earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business segments. We define EBIT as net income (loss) adjusted for (i) items that do not impact our income (loss) from continuing operations, such as extraordinary items, discontinued operations and the impact of accounting changes, (ii) income taxes, (iii) interest and debt expense and (iv) distributions on preferred interests of consolidated subsidiaries. Our business operations consist of both consolidated businesses as well as substantial investments in unconsolidated affiliates. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the performance of all of our businesses and investments. Also, we exclude interest and debt expense and distributions on preferred interests of consolidated subsidiaries so that investors may evaluate our operating results without regard to our financing methods or capital structure. EBIT may not be comparable to measures used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flow. Below is reconciliation of our EBIT to our income (loss) from continuing operations for the three years ended December 31:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(In millions)		
Total EBIT	\$ 312	\$ 707	\$ 958
Interest and debt expense	(341)	(407)	(425)
Affiliated interest expense, net	—	(41)	(9)
Distributions on preferred interests of consolidated subsidiaries	—	(17)	(35)
Income taxes	<u>(12)</u>	<u>(43)</u>	<u>(143)</u>
Income (loss) from continuing operations	<u>\$ (41)</u>	<u>\$ 199</u>	<u>\$ 346</u>

The following tables reflect our segment results as of and for each of the three years ended December 31:

	Segments					Total
	As of or for the Year Ended December 31, 2004					
	Regulated	Non-regulated			Corporate ⁽¹⁾	
Pipelines	Production	Power	Field Services			
	(In millions)					
Revenues from external customers						
Domestic	\$ 848	\$ 646 ⁽²⁾	\$ 59	\$481	\$ 53	\$2,087
Foreign	—	—	90	—	—	90
Intersegment revenue	10	44	—	1	(55)	—
Operation and maintenance	252	173	83	26	(4)	530
Depreciation, depletion and amortization	123	315	11	6	12	467
Loss (gain) on long-lived assets	(1)	—	102	5	—	106
Operating income (loss)	\$ 350	\$ 174	\$ (97)	\$ 46	\$ 2	\$ 475
Earnings (losses) from unconsolidated affiliates	72	(3)	(273)	11	—	(193)
Other income	17	—	15	—	12	44
Other expense	(5)	—	6	(2)	(13)	(14)
EBIT	<u>\$ 434</u>	<u>\$ 171</u>	<u>\$(349)</u>	<u>\$ 55</u>	<u>\$ 1</u>	<u>\$ 312</u>
Discontinued operations, net of income taxes (Restated) ⁽⁶⁾	\$ —	\$ (36)	\$ —	\$ —	\$(79)	\$ (115)
Assets of continuing operations ⁽³⁾						
Domestic	5,717	1,769	223	312	425	8,446
Foreign ⁽⁴⁾	—	231	493	—	68	792
Capital expenditures and investments in and advances to unconsolidated affiliates, net ⁽⁵⁾	527	276	(1)	9	1	812
Total investments in unconsolidated affiliates	362	—	478	48	6	894

⁽¹⁾ Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of \$55 million and an operation and maintenance elimination of less than \$1 million, which is included in the “Corporate” column, to remove intersegment transactions.

⁽²⁾ Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production.

⁽³⁾ Excludes assets of discontinued operations of \$106 million (see Note 2).

⁽⁴⁾ Of total foreign assets, approximately \$352 million relates to property, plant, and equipment and approximately \$360 million relates to investments in and advances to unconsolidated affiliates.

⁽⁵⁾ Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

⁽⁶⁾ See Note 1 to the consolidated financial statements for a discussion of the restatement of these amounts.

Segments
As of or for the Year Ended December 31, 2003

	Regulated	Non-regulated			Corporate ⁽¹⁾	Total
	Pipelines	Production	Power	Field Services		
						(In millions)
Revenues from external customers						
Domestic	\$ 915	\$ 710 ⁽²⁾	\$ 175	\$328	\$ 38	\$ 2,166
Foreign	2	—	77	2	—	81
Intersegment revenue	1	112	—	26	(55)	84 ⁽³⁾
Operation and maintenance	246	164	105	20	(7)	528
Depreciation, depletion and amortization	108	347	14	7	11	487
Ceiling test charges	—	39	—	—	—	39
Loss (gain) on long-lived assets	(11)	5	28	(13)	(1)	8
Operating income (loss)	\$ 397	\$ 207	\$ 22	\$ 41	\$ (19)	\$ 648
Earnings (losses) from unconsolidated affiliates	75	10	(6)	(93)	2	(12)
Other income	32	2	13	—	19	66
Other expense	(4)	—	10	—	(1)	5
EBIT	<u>\$ 500</u>	<u>\$ 219</u>	<u>\$ 39</u>	<u>\$ (52)</u>	<u>\$ 1</u>	<u>\$ 707</u>
Discontinued operations, net of income taxes (Restated) ⁽⁶⁾	\$ —	\$ 11	\$ —	\$ —	\$(1,297)	\$(1,286)
Cumulative effect of accounting changes, net of income taxes	(4)	(6)	—	(2)	—	(12)
Assets of continuing operations ⁽⁴⁾						
Domestic (Restated) ⁽⁶⁾	5,271	1,950	1,533	224	695	9,673
Foreign	—	233	601	—	99	933
Capital expenditures and investments in and advances to unconsolidated affiliates, net ⁽⁵⁾	192	600	(4)	14	(19)	783
Total investments in unconsolidated affiliates	397	52	804	54	5	1,312

⁽¹⁾ Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of \$48 million and an operation and maintenance expense elimination of \$1 million which is included in the “Corporate” column, to remove intersegment transactions.

⁽²⁾ Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production.

⁽³⁾ Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

⁽⁴⁾ Excludes assets of discontinued operations of \$1.8 billion (see Note 2).

⁽⁵⁾ Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

⁽⁶⁾ See Note 1 to the consolidated financial statements for a discussion of the restatement of these amounts.

	Segments					Total
	As of or for the Year Ended December 31, 2002					
	Regulated	Non-regulated			Corporate ⁽¹⁾	
Pipelines	Production	Power	Field Services			
	(In millions)					
Revenues from external customers						
Domestic	\$ 901	\$1,092 ⁽²⁾	\$1,051	\$ 404	\$ 48	\$ 3,496
Foreign	3	—	154	3	—	160
Intersegment revenue	30	95	11	53	(63)	126 ⁽³⁾
Operation and maintenance expenses...	235	219	239	45	17	755
Depreciation, depletion and amortization	116	447	19	14	13	609
Ceiling test charges	—	422	—	—	—	422
Loss (gain) on long-lived assets	(12)	1	18	(21)	2	(12)
Operating income (loss)	\$ 419	\$ 24	\$ 397	\$ 68	\$ (63)	\$ 845
Earnings (losses) from unconsolidated affiliates	105	4	57	(53)	—	113
Other income	16	1	19	—	34	70
Other expense	(3)	—	(57)	—	(10)	(70)
EBIT	<u>\$ 537</u>	<u>\$ 29</u>	<u>\$ 416</u>	<u>\$ 15</u>	<u>\$ (39)</u>	<u>\$ 958</u>
Discontinued operations, net of income taxes	\$ —	\$ (38)	\$ —	\$ —	\$ (357)	\$ (395)
Cumulative effect of accounting changes, net of income taxes	—	—	14	—	—	14
Assets of continuing operations ⁽⁴⁾						
Domestic	5,128	2,203	1,698	451	583	10,063
Foreign	47	131	623	14	170	985
Capital expenditures and investments in and advances to unconsolidated affiliates, net ⁽⁵⁾	252	949	(26)	20	99	1,294
Total investments in unconsolidated affiliates	404	90	851	143	17	1,505

⁽¹⁾ Includes eliminations of intercompany transactions. Our intersegment revenues, along with our intersegment operating expenses, were incurred in the normal course of business between our operating segments. We recorded an intersegment revenue elimination of \$30 million and an operation and maintenance expense elimination of \$5 million, which is included in the "Corporate" column, to remove intersegment transactions.

⁽²⁾ Revenues from external customers include gains and losses related to our hedging of price risk associated with our natural gas and oil production.

⁽³⁾ Relates to intercompany activities between our continuing operating segments and our discontinued petroleum markets operations.

⁽⁴⁾ Excludes assets of discontinued operations of \$4.5 billion (see Note 2).

⁽⁵⁾ Amounts are net of third party reimbursements of our capital expenditures and returns of invested capital.

16. Investments in, Earnings from and Transactions with Unconsolidated Affiliates and Related Parties

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are interstate pipelines and power generation plants. Our investment balance was less than our equity in the net assets of these investments as of December 31, 2004 and 2003 by \$217 million and \$37 million. These differences primarily relate to unamortized purchase price adjustments, net of asset impairment charges. Our net ownership interest, investments in and earnings (losses) from our unconsolidated affiliates are as follows as of and for the year ended December 31:

	Net Ownership Interest		Investment		Earnings from Unconsolidated Affiliates		
	2004 (Percent)	2003	2004 (In millions)	2003 (In millions)	2004 (In millions)	2003 (In millions)	2002
Domestic:							
Great Lakes Gas Transmission ⁽¹⁾	50	50	\$316	\$ 325	\$ 65	\$ 57	\$ 63
Midland Cogeneration Venture ⁽²⁾	44	44	191	348	(171)	29	28
Javelina	40	40	45	40	15	(2)	—
Wyco Development	50	50	26	24	2	2	2
Bastrop Company ⁽³⁾	—	50	—	73	(1)	(48)	(5)
Mobile Bay Processing ⁽³⁾	—	42	—	11	—	(48)	(2)
Blue Lake Gas Storage ⁽⁴⁾	—	75	—	30	—	9	8
Dauphin Island ⁽³⁾	—	15	—	—	—	(40)	(1)
Alliance Pipeline Limited Partnership ⁽⁵⁾	—	—	—	—	—	—	25
Aux Sable NGL ⁽⁵⁾	—	—	—	—	—	—	(50)
Other Domestic Investments	various	various	29	77	(3)	27	11
Total domestic			607	928	(93)	(14)	79
Foreign:							
EGE Itabo	25	25	88	87	1	1	(2)
EGE Fortuna	25	25	65	59	6	3	5
Khulna Power Company	74	74	21	40	(18)	1	1
Habibullah Power ⁽⁶⁾	50	50	20	48	(46)	(3)	10
Saba Power Company	94	94	7	59	(51)	4	7
Other Foreign Investments ⁽⁶⁾	various	various	86	91	8	(4)	13
Total foreign			287	384	(100)	2	34
Total investments in unconsolidated affiliates			\$894	\$1,312			
Total earnings (losses) from unconsolidated affiliates					\$(193)	\$(12)	\$113

⁽¹⁾ Includes a 47 percent general partner interest in Great Lakes Gas Transmission Limited Partnership and a 3 percent limited partner interest through our ownership in Great Lakes Gas Transmission Company.

⁽²⁾ Our ownership interest consists of a 38.1 percent general partner interest and 5.4 percent limited partner interest.

⁽³⁾ In 2004, we completed the sale of our interest in this investment.

⁽⁴⁾ Consolidated in 2004.

⁽⁵⁾ In 2003 we completed the sale of our interest in this investment.

⁽⁶⁾ As of December 31, 2004 and 2003, we also had outstanding advances of \$64 million and \$90 million related to our investment in Habibullah Power. We also had other outstanding advances of \$9 million and \$13 million related to our other foreign investments as of December 31, 2004 and 2003.

Our impairment charges and gains and losses on sales of equity investments that are included in equity earnings (losses) from unconsolidated affiliates during 2004, 2003 and 2002 consisted of the following:

<u>Investment</u>	<u>Pre-tax Gain (Loss)</u> (In millions)	<u>Cause of Impairments or Gain (Loss)</u>
<i>2004</i>		
Asian assets	\$(131)	Anticipated sales of investments
Midland Cogeneration Venture	(161)	Decline in investment's fair value based on increased fuel costs
	<u>\$(292)</u>	
<i>2003</i>		
Bastrop Company	\$ (43)	Decision to sell investment
Dauphin Island Gathering/Mobile Bay Processing	(86)	Decline in the investments' fair value based on the devaluation of the underlying assets
Other investments	<u>1</u>	
	<u>\$(128)</u>	
<i>2002</i>		
Aux Sable NGL	<u>\$ (47)</u>	Sale of investment

Below is summarized financial information of our proportionate share of unconsolidated affiliates. This information includes affiliates in which we hold a less than 50 percent interest as well as those in which we hold a greater than 50 percent interest. We received distributions and dividends of \$108 million, \$98 million and \$127 million in 2004, 2003 and 2002, which includes \$2 million, \$17 million and \$6 million of returns of capital, in 2004, 2003 and 2002 from our investments. Our proportional shares of the unconsolidated affiliates in which we hold a greater than 50 percent interest had net income of \$21 million, \$20 million and \$25 million in 2004, 2003 and 2002 and total assets of \$474 million and \$536 million as of December 31, 2004 and 2003.

	<u>Year Ended December 31,</u>		
	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(Unaudited) (In millions)		
Operating results data:			
Operating revenues	\$830	\$807	\$799
Operating expenses	630	590	542
Income from continuing operations	83	90	125
Net income	83	90	148
	<u>December 31,</u>		
	<u>2004</u>	<u>2003</u>	
	(Unaudited) (In millions)		
Financial position data:			
Current assets	\$ 517	\$ 468	
Non-current assets	2,013	2,386	
Short-term debt	158	99	
Other current liabilities	183	249	
Long-term debt	813	905	
Other non-current liabilities	194	181	
Minority interest	71	71	
Equity in net assets	1,111	1,349	

Contingent Matters that Could Impact Our Investments

Economic Conditions in the Dominican Republic. We have investments in power projects in the Dominican Republic with an aggregate exposure of approximately \$103 million. We own an approximate 48 percent interest in a 67 MW heavy fuel oil fired power project known as the CEPP project. We also own an approximate 25 percent ownership interest in a 416 MW power generating complex known as Itabo. In 2003, an economic crisis developed in the Dominican Republic resulting in a significant devaluation of the Dominican peso. As a consequence of economic conditions described above, combined with the high prices on imported fuels and due to their inability to pass through these high fuel costs to their consumers, the local distribution companies that purchase the electrical output of these facilities have been delinquent in their payments to CEPP and Itabo, and to the other generating facilities in the Dominican Republic since April 2003. The failure to pay generators has resulted in the inability of the generators to purchase fuel required to produce electricity resulting in significant energy shortfalls in the country. In addition, a recent local court decision has resulted in the potential inability of CEPP to continue to receive payments for its power sales which may affect CEPP's ability to operate. We are contesting the local court decision. We continue to monitor the economic and regulatory situation in the Dominican Republic and as new information becomes available or future material developments arise, it is possible that impairments of these investments may occur.

Related Party Transactions

The following table shows revenues and charges resulting from transactions with our related parties:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
	(In millions)		
Revenues	\$750	\$1,091	\$1,619
Cost of sales	114	88	177
Reimbursement for operating expenses	3	4	3
Charges from affiliates	209	282	275
Other income	14	15	9

Revenues and Expenses. We enter into transactions with other El Paso subsidiaries and unconsolidated affiliates in the ordinary course of business to transport, sell and purchase natural gas and liquids and various contractual agreements for trading activities. Substantially all of our revenues and cost of sales from related parties for the years ended December 31, 2004, 2003 and 2002 were with El Paso affiliates, and primarily related to transactions with our Production segment. We have also entered into a service agreement with El Paso that provides for a reimbursement of 2.5 cents per MMBtu in 2005 for our expected administrative costs associated with hedging transactions we entered into in December 2004.

El Paso allocates a portion of its general and administrative expenses to us. The allocation is based on the estimated level of effort devoted to our operations and the relative size of our EBIT, gross property and payroll. For the years ended December 2004, 2003 and 2002, the annual charges were \$70 million, \$152 million and \$146 million. During 2004, 2003 and 2002 El Paso Natural Gas Company and Tennessee Gas Pipeline Company allocated payroll and other expenses to us associated with our shared pipeline services. The allocated expenses are based on the estimated level of staff and their expenses to provide the services. For the years ended December 2004, 2003 and 2002 the annual charges were \$54 million, \$48 million and \$40 million. El Paso also provides our Production segment administrative and other shared production services and allocated \$75 million, \$73 million and \$76 million in 2004, 2003 and 2002, net of capitalized amounts. We believe the allocation methods are reasonable.

Cash Management Program and Affiliate Receivables/Payables. We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. We have historically and consistently borrowed cash from El Paso under this program. As of December 31, 2004 and December 31, 2003, we had borrowed \$166 million and \$906 million. The market rate of interest as of December 31, 2004 was 2.0% and at December 31, 2003, it was 2.8%. On December 31, 2003, El Paso's Board of Directors authorized a capital contribution of

\$1.5 billion to us as further discussed below, which reduced our total payables outstanding under this program. We also had other notes payable to related parties of \$45 million and \$43 million and other accounts payable to related parties of \$61 million and \$67 million at December 31, 2004 and December 31, 2003.

In addition, we had a demand note receivable with El Paso of \$177 million at December 31, 2004, at an interest rate of 2.7%. At December 31, 2003, the demand note receivable was \$275 million at an interest rate of 1.7%. Also, at December 31, 2004 and December 31, 2003, we had accounts and notes receivable from related parties of \$87 million and \$167 million. In addition, we had non-current advances to unconsolidated affiliates of \$69 million and \$127 million included in other non-current assets at December 31, 2004 and at December 31, 2003.

Affiliate income taxes. We are a party to a tax accrual policy with El Paso whereby El Paso files U.S. and certain state tax returns on our behalf. In certain states, we file and pay directly to the state taxing authorities. We have U.S. federal and state income taxes payable of \$46 million and \$42 million at December 31, 2004 and 2003, included in other current liabilities on our balance sheets. The balances due to El Paso will become payable under the tax accrual policy. See Note 1 for a discussion of our tax accrual policy.

Contributions from Parent. In 2004, El Paso made a capital contribution of \$45 million to us. On December 31, 2003, El Paso's Board of Directors authorized a capital contribution of \$1.5 billion to us, which was paid in 2003. Also in 2003, El Paso made an additional capital contribution of \$24 million to us. In December 2002, El Paso contributed to us its interest in one of its subsidiaries to us that had a book value of \$139 million. These contributions are reflected in our stockholder's equity statement as increases in our additional paid in capital.

Acquisitions and Divestitures. In March 2002, we acquired assets with a net book value, net of deferred taxes, of approximately \$8 million from El Paso.

Additionally, we sold natural gas and oil properties to another subsidiary of El Paso in 2002. Net proceeds from these sales were \$404 million, and because this sale involved entities under the common control of El Paso, we did not recognize a gain or loss on the properties sold. We recorded the difference between the net book value and proceeds of \$170 million as an increase to additional paid in capital.

In November 2002, we sold our stock in Coastal Mart, Inc., one of our wholly-owned subsidiaries, to El Paso Remediation Company, a wholly owned subsidiary of El Paso. We recorded a receivable of \$42 million, which was based on the book value of the company (since the sale occurred between entities under common control). We did not recognize a gain or loss on this sale.

Other. During the first quarter of 2004, Coastal Stock Company, our wholly-owned subsidiary, issued 68,000 shares of its Class A Preferred Stock to a subsidiary of El Paso for \$71 million. We included the proceeds from the issuance of these shares as securities of subsidiaries in our balance sheet.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholder of
El Paso CGP Company:

In our opinion, based on our audits and the report of other auditors, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the consolidated financial position of El Paso CGP Company and its subsidiaries (the "Company") at December 31, 2004 and 2003, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, based on our audits, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We did not audit the consolidated financial statements of Great Lakes Gas Transmission Limited Partnership (the "Partnership"), an equity method investment of the Company, which constitutes investments in unconsolidated affiliates of \$316 million and \$325 million at December 31, 2004 and 2003, respectively, and earnings from unconsolidated affiliates of \$65 million, \$57 million and \$63 million, respectively, for the three years in the period ended December 31, 2004. Those statements were audited by other auditors, whose report thereon has been furnished to us, and our opinion expressed herein, insofar as it related to the amounts included for the Partnership is based solely on the report of the other auditors. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 1, the Company restated its 2003 and 2004 financial statements. As discussed in Note 1, the Company adopted FASB Financial Interpretation No. 46, *Consolidation of Variable Interest Entities* on January 1, 2004; FASB Staff Position No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* on July 1, 2004; Statement of Financial Accounting Standards (SFAS) No. 143, *Accounting for Asset Retirement Obligations* on January 1, 2003; SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity* on July 1, 2003; SFAS No. 142, *Goodwill and Other Intangible Assets* and SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* on January 1, 2002; DIG Issue No. C-16, *Scope Exceptions: Applying the Normal Purchases and Sales Exception to Contracts that Combine a Forward Contract and Purchased Option Contract* on July 1, 2002; and EITF Issue No. 02-3, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities, Consensus 2* on October 1, 2002.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
April 15, 2005, except for the restatement
described in the second paragraph of
Note 1 to the consolidated financial statements
as to which the date is June 15, 2005

Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below:

	Quarters Ended				Total
	March 31 (Restated) ⁽²⁾	June 30	September 30	December 31	
	(In millions)				
2004					
Operating revenues	\$ 537	\$ 505	\$518	\$ 617	\$ 2,177
Loss (gain) on long-lived assets	88	—	6	12	106
Operating income	89	148	91	147	475
Income (loss) from continuing operations	\$ 10	\$ 61	\$ 38	\$(150)	\$ (41)
Discontinued operations, net of income taxes ⁽¹⁾	(96)	(11)	(12)	4	(115)
Net income (loss)	<u>\$ (86)</u>	<u>\$ 50</u>	<u>\$ 26</u>	<u>\$(146)</u>	<u>\$ (156)</u>

	Quarters Ended				Total
	March 31	June 30	September 30	December 31 (Restated) ⁽²⁾	
	(In millions)				
2003					
Operating revenues	\$ 723	\$ 604	\$496	\$ 508	\$ 2,331
Ceiling test charges	—	—	39	—	39
Loss (gain) on long-lived assets	—	(30)	6	32	8
Operating income	272	228	79	69	648
Income (loss) from continuing operations ...	\$ 134	\$ 47	\$ —	\$ 18	\$ 199
Discontinued operations, net of income taxes ⁽¹⁾	(220)	(931)	(69)	(66)	(1,286)
Cumulative effect of accounting changes, net of income taxes	(12)	—	—	—	(12)
Net loss	<u>\$ (98)</u>	<u>\$(884)</u>	<u>\$(69)</u>	<u>\$ (48)</u>	<u>\$(1,099)</u>

⁽¹⁾ Our petroleum markets, our Canadian and certain other international natural gas and oil production operations and our coal mining operations are classified as discontinued operations. (See Note 2 for further discussion).

⁽²⁾ Listed below are the amounts we originally reported in our Form 10-K for the quarters ended:

	Quarters Ended	
	March 31, 2004	December 31, 2003
Discontinued operations, net of income taxes	\$(128)	\$(101)
Net income (loss)	(118)	(83)

Supplemental Natural Gas and Oil Operations (Unaudited)

Our Production segment is engaged in the exploration for and the acquisition, development and production of natural gas, oil and natural gas liquids in the United States and Brazil. In the United States, we have onshore operations and properties primarily in Texas, Utah, West Virginia and Wyoming and offshore operations and properties in federal and state waters in the Gulf of Mexico. Internationally, we have exploration and production rights in Brazil.

Capitalized costs relating to natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31:

	United States	Brazil	Worldwide
	(In millions)		
2004			
Natural gas and oil properties:			
Costs subject to amortization ⁽¹⁾	\$6,805	\$207	\$7,012
Costs not subject to amortization	55	86	141
	6,860	293	7,153
Less accumulated depreciation, depletion and amortization	5,235	82	5,317
Net capitalized costs	\$1,625	\$211	\$1,836
SFAS No. 143 abandonment liability	\$ 149	\$ —	\$ 149
2003			
Natural gas and oil properties:			
Costs subject to amortization ⁽¹⁾	\$6,847	\$146	\$6,993
Costs not subject to amortization	119	117	236
	6,966	263	7,229
Less accumulated depreciation, depletion and amortization	5,307	58	5,365
Net capitalized costs	\$1,659	\$205	\$1,864
SFAS No. 143 abandonment liability	\$ 131	\$ —	\$ 131

⁽¹⁾ In January 1, 2003, we adopted SFAS No. 143 which is further discussed in Note 1. Included in our costs subject to amortization at December 31, 2004 and 2003 are SFAS No. 143 asset values of \$88 million and \$77 million primarily for the United States.

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows at December 31:

	<u>United States</u>	<u>Brazil</u>	<u>Worldwide</u>
	(In millions)		
2004			
Property acquisition costs			
Proved properties	\$ 6	\$—	\$ 6
Unproved properties	4	3	7
Exploration costs ⁽¹⁾	87	24	111
Development costs ⁽¹⁾	<u>150</u>	<u>1</u>	<u>151</u>
Costs expended	247	28	275
Asset retirement obligation costs	<u>11</u>	<u>—</u>	<u>11</u>
Total costs incurred	<u>\$258</u>	<u>\$28</u>	<u>\$286</u>
2003			
Property acquisition costs			
Unproved properties	\$ 9	\$ 4	\$ 13
Exploration costs ⁽¹⁾	216	95	311
Development costs ⁽¹⁾	<u>270</u>	<u>—</u>	<u>270</u>
Costs expended	495	99	594
Asset retirement obligation costs ⁽²⁾	<u>77</u>	<u>—</u>	<u>77</u>
Total costs incurred	<u>\$572</u>	<u>\$99</u>	<u>\$671</u>
2002			
Property acquisition costs			
Proved properties	\$ 23	\$—	\$ 23
Unproved properties	12	9	21
Exploration costs	197	45	242
Development costs	<u>569</u>	<u>—</u>	<u>569</u>
Total costs incurred	<u>\$801</u>	<u>\$54</u>	<u>\$855</u>

⁽¹⁾ Excludes approximately \$32 million and \$57 million that was paid in 2004 and 2003 by third parties under net profits interest agreements described beginning on page 102.

⁽²⁾ In January 2003, we adopted SFAS No. 143, which is further discussed in Note 1. The cumulative effect of adopting SFAS No. 143 was \$6 million.

The table above includes capitalized internal costs incurred in connection with the acquisition, development and exploration of natural gas and oil reserves of \$21 million, \$50 million, and \$70 million and capitalized interest of \$4 million, \$7 million and \$7 million for the years ended December 31, 2004, 2003 and 2002.

In our January 1, 2005 reserve report, the amounts estimated to be spent in 2005, 2006 and 2007 to develop our worldwide booked proved undeveloped reserves are \$27 million, \$71 million and \$113 million.

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditure that are not being amortized as of December 31, 2004, pending determination of proved reserves:

	Cumulative Balance December 31, 2004	Costs Excluded for Years Ended December 31,			Cumulative Balance December 31, 2001
		2004	2003	2002	
Worldwide ⁽¹⁾⁽²⁾					
Acquisition	\$ 57	\$13	\$17	\$15	\$12
Exploration	81	28	46	6	1
Development	3	1	—	—	2
	<u>\$141</u>	<u>\$42</u>	<u>\$63</u>	<u>\$21</u>	<u>\$15</u>

⁽¹⁾ Includes operations in the United States and Brazil.

⁽²⁾ Includes capitalized interest of \$4 million, \$2 million, and less than \$1 million for the years ended December 31, 2004, 2003, and 2002.

Projects presently excluded from amortization are in various stages of evaluation. The majority of these costs are expected to be included in the amortization calculation in the years 2005 through 2008. For the United States, the unit of production depletion cost per Mcfe, including ceiling test charges, was \$2.42, \$2.06, and \$2.98 in 2004, 2003, and 2002. Excluding ceiling test charges, our amortization expense per Mcfe would have been \$2.42, \$1.84 and \$1.52 in 2004, 2003 and 2002. Included in our depreciation, depletion, and amortization expense is accretion expense of \$0.12 and \$0.08 per Mcfe for 2004 and 2003 attributable to SFAS No. 143 which we adopted in January 2003.

Net quantities of proved developed and undeveloped reserves of natural gas and NGL, including condensate and crude oil, and changes in these reserves at December 31, 2004 are presented below. Information in this table is based on our internal reserve report. Ryder Scott Company, an independent petroleum engineering firm prepared an estimate of our natural gas and oil reserves for 82 percent of our properties by volume. The total estimate of proved reserves prepared by Ryder Scott Company was within one percent of our internally prepared estimates presented in these tables. Ryder Scott Company was retained by and reports to the Audit Committee of El Paso's Board of Directors. The properties reviewed by Ryder Scott represented 84 percent of our proved properties based on value. This information is consistent with estimates of reserves filed with other federal agencies except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

	Natural Gas (Bcf)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves ⁽¹⁾			
January 1, 2002	1,475	—	1,475
Revisions of previous estimates	(164)	—	(164)
Extensions, discoveries and other	279	—	279
Purchases of reserves in place	—	—	—
Sales of reserves in place	(504)	—	(504)
Production	<u>(247)</u>	<u>—</u>	<u>(247)</u>
December 31, 2002	839	—	839
Revisions of previous estimates	(30)	—	(30)
Extensions, discoveries and other	91	—	91
Purchases of reserves in place	3	—	3
Sales of reserves in place ⁽²⁾	(136)	—	(136)
Production	<u>(142)</u>	<u>—</u>	<u>(142)</u>
December 31, 2003	625	—	625
Revisions of previous estimates	(40)	—	(40)
Extensions, discoveries and other	26	—	26
Purchases of reserves in place	—	—	—
Sales of reserves in place ⁽²⁾	(3)	—	(3)
Production	<u>(96)</u>	<u>—</u>	<u>(96)</u>
December 31, 2004	<u>512</u>	<u>—</u>	<u>512</u>
Proved developed reserves			
December 31, 2002	633	—	633
December 31, 2003	502	—	502
December 31, 2004	419	—	419

⁽¹⁾ Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

⁽²⁾ Sales of reserves in place include 3,434 MMcf and 11,416 MMcf of natural gas conveyed to third parties under net profits interest agreements in 2004 and 2003.

	<u>Oil and Condensate (MBbls)</u>		
	<u>United States</u>	<u>Brazil</u>	<u>Worldwide</u>
Net proved developed and undeveloped reserves ⁽¹⁾			
January 1, 2002	23,846	—	23,846
Revisions of previous estimates	1,294	—	1,294
Extensions, discoveries and other	3,125	—	3,125
Purchases of reserves in place	—	—	—
Sales of reserves in place	(2,083)	—	(2,083)
Production	<u>(5,136)</u>	<u>—</u>	<u>(5,136)</u>
December 31, 2002	21,046	—	21,046
Revisions of previous estimates	784	—	784
Extensions, discoveries and other	2,332	20,543	22,875
Purchases of reserves in place	5	—	5
Sales of reserves in place ⁽²⁾	(534)	—	(534)
Production	<u>(3,871)</u>	<u>—</u>	<u>(3,871)</u>
December 31, 2003	19,762	20,543	40,305
Revisions of previous estimates	319	252	571
Extensions, discoveries and other	1,889	—	1,889
Purchases of reserves in place ⁽²⁾	—	—	—
Sales of reserves in place	(8)	—	(8)
Production	<u>(2,603)</u>	<u>—</u>	<u>(2,603)</u>
December 31, 2004	<u>19,359</u>	<u>20,795</u>	<u>40,154</u>
Proved developed reserves			
December 31, 2002	15,290	—	15,290
December 31, 2003	13,577	—	13,577
December 31, 2004	13,972	—	13,972

⁽¹⁾ Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

⁽²⁾ Sales of reserves in place include 8 MBbl and 428 MBbl of oil and condensate conveyed to third parties under net profits agreements in 2004 and 2003.

	Natural Gas Liquids (MBbls)		
	United States	Brazil	Worldwide
Net proved developed and undeveloped reserves ⁽¹⁾			
January 1, 2002	25,680	—	25,680
Revisions of previous estimates	(3,240)	—	(3,240)
Extensions, discoveries and other	3,989	—	3,989
Purchases of reserves in place	—	—	—
Sales of reserves in place	(9,200)	—	(9,200)
Production	<u>(1,792)</u>	<u>—</u>	<u>(1,792)</u>
December 31, 2002	15,437	—	15,437
Revisions of previous estimates	(3,048)	—	(3,048)
Extensions, discoveries and other	1,323	—	1,323
Purchases of reserves in place	38	—	38
Sales of reserves in place ⁽²⁾	(485)	—	(485)
Production	<u>(2,107)</u>	<u>—</u>	<u>(2,107)</u>
December 31, 2003	11,158	—	11,158
Revisions of previous estimates	(758)	—	(758)
Extensions, discoveries and other	53	—	53
Purchases of reserves in place	—	—	—
Sales of reserves in place ⁽²⁾	(47)	—	(47)
Production	<u>(1,807)</u>	<u>—</u>	<u>(1,807)</u>
December 31, 2004	<u>8,599</u>	<u>—</u>	<u>8,599</u>
Proved developed reserves			
December 31, 2002	13,175	—	13,175
December 31, 2003	9,559	—	9,559
December 31, 2004	7,684	—	7,684

⁽¹⁾ Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate.

⁽²⁾ Sales of reserves in place include 47 MBbl and 85 MBbl of NGL conveyed to third parties under net profits agreements in 2004 and 2003.

During 2004, we had approximately 43 Bcfe of negative reserve revisions in the United States that were largely performance-driven. Our negative reserve revisions were concentrated in the Texas Gulf Coast region and offshore in the Gulf of Mexico:

Onshore. The onshore region recorded 12 Bcfe of positive reserve revisions. These revisions were created by better-than-anticipated performance in the Rockies.

Texas Gulf Coast. The Texas Gulf Coast region recorded 20 Bcfe of negative reserve revisions. The negative revisions were caused by performance revisions to proved producing wells, mechanical failures and lower-than-expected results from the 2004 development drilling program.

Offshore. The offshore region recorded 34 Bcfe of negative reserve revisions in the Gulf of Mexico. The revisions are a result of mechanical failures and adjustments to proved undeveloped reserves as a result of production performance in offsetting locations.

There are numerous uncertainties inherent in estimating quantities of proved reserves projecting future rates of production, and projecting the timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. All estimates of proved reserves are determined according to the rules

prescribed by the SEC. These rules indicate that the standard of “reasonable certainty” be applied to proved reserve estimates. This concept of reasonable certainty implies that as more technical data becomes available, a positive, or upward, revision is more likely than a negative, or downward, revision. Estimates are subject to revision based upon a number of factors, including reservoir performance, prices, economic conditions and government restrictions. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from natural gas and oil properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2004.

In 2003, we entered into agreements to sell interests in a maximum of 42 wells to a subsidiary of Lehman Brothers and a subsidiary of Nabors Industries. As these wells are developed, Lehman and Nabors will pay 70 percent of the drilling and completion costs in exchange for 70 percent of the net profits of the wells sold. As each well is commenced, Lehman and Nabors receive an overriding royalty interest in the form of a net profits interest in the well, under which they are entitled to receive 70 percent of the aggregate net profits of all wells until they have recovered 117.5 percent of their aggregate investment. Upon this recovery, the net profits interest will convert to a two percent overriding royalty interest in the wells for the remainder of the wells’ productive life. We do not guarantee a return or the recovery of Lehman and Nabors costs. All parties to the agreement have the right to cease participation in the agreement at any time, at which time Lehman and Nabors will continue to receive their net profits interest on wells previously started, but will relinquish their right to participate in any future wells. During 2004, we have sold interests in 22 wells and total proved reserves of 3,434 MMcf of natural gas and 55 MBbl of oil, condensate and NGL. They have paid \$32 million of drilling and development costs and were paid \$41 million of the revenues net of \$4 million of expenses associated with these wells for the year ended December 31, 2004. In March 2005, we acquired all of the interests held by the Lehman subsidiary for \$22 million.

Results of operations from producing activities by fiscal year were as follows at December 31:

	<u>United States</u>	<u>Brazil</u>	<u>Worldwide</u>
	(In millions)		
2004			
Net Revenues			
Sales to external customers	\$ 183	\$—	\$ 183
Intersegment sales	492	—	492
Total	<u>675</u>	<u>—</u>	<u>675</u>
Production costs ⁽¹⁾	(107)	—	(107)
Depreciation, depletion and amortization ⁽²⁾	<u>(315)</u>	<u>—</u>	<u>(315)</u>
	253	—	253
Income tax expense	(92)	—	(92)
Results of operations from producing activities	<u>\$ 161</u>	<u>\$—</u>	<u>\$ 161</u>
2003			
Net Revenues			
Sales to external customers	\$ 683	\$—	\$ 683
Intersegment sales	109	—	109
Total	<u>792</u>	<u>—</u>	<u>792</u>
Production costs ⁽¹⁾	(114)	—	(114)
Depreciation, depletion and amortization ⁽²⁾	<u>(347)</u>	<u>—</u>	<u>(347)</u>
Ceiling test and other charges	<u>(34)</u>	<u>(5)</u>	<u>(39)</u>
	297	(5)	292
Income tax expense	(106)	2	(104)
Results of operations from producing activities	<u>\$ 191</u>	<u>\$(3)</u>	<u>\$ 188</u>
2002			
Net Revenues			
Sales to external customers	\$1,021	\$—	\$1,021
Intersegment sales	106	—	106
Total	<u>1,127</u>	<u>—</u>	<u>1,127</u>
Production costs ⁽¹⁾	(162)	—	(162)
Depreciation, depletion and amortization	<u>(446)</u>	<u>—</u>	<u>(446)</u>
Ceiling test and other charges	<u>(417)</u>	<u>—</u>	<u>(417)</u>
	102	—	102
Income tax expense	(35)	—	(35)
Results of operations from producing activities	<u>\$ 67</u>	<u>\$—</u>	<u>\$ 67</u>

⁽¹⁾ Production costs include lease operating costs and production related taxes (including ad valorem and severance taxes).

⁽²⁾ In January 2003 we adopted SFAS No. 143, which is further discussed in Note 1. Our depreciation, depletion and amortization includes accretion expense for SFAS No. 143 asset retirement obligations of \$14 million and \$16 million primarily for the United States in 2004 and 2003.

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves follows at December 31:

	<u>United States</u>	<u>Brazil</u>	<u>Worldwide</u>
	(In millions)		
2004			
Future cash inflows ⁽¹⁾	\$ 4,059	\$ 810	\$ 4,869
Future production costs	(1,087)	(76)	(1,163)
Future development costs	(544)	(236)	(780)
Future income tax expenses	(272)	(111)	(383)
Future net cash flows	2,156	387	2,543
10% annual discount for estimated timing of cash flows	(655)	(183)	(838)
Standardized measure of discounted future net cash flows	<u>\$ 1,501</u>	<u>\$ 204</u>	<u>\$ 1,705</u>
Standardized measure of discounted future net cash flows, including effects of hedging activities	<u>\$ 1,388</u>	<u>\$ 204</u>	<u>\$ 1,592</u>
2003			
Future cash inflows ⁽¹⁾	\$ 4,445	\$ 588	\$ 5,033
Future production costs	(967)	(65)	(1,032)
Future development costs	(564)	(236)	(800)
Future income tax expenses	(362)	(75)	(437)
Future net cash flows	2,552	212	2,764
10% annual discount for estimated timing of cash flows	(735)	(128)	(863)
Standardized measure of discounted future net cash flows	<u>\$ 1,817</u>	<u>\$ 84</u>	<u>\$ 1,901</u>
Standardized measure of discounted future net cash flows, including effects of hedging activities	<u>\$ 1,729</u>	<u>\$ 84</u>	<u>\$ 1,813</u>
2002			
Future cash inflows ⁽¹⁾	\$ 4,632	\$ —	\$ 4,632
Future production costs	(1,071)	—	(1,071)
Future development costs	(623)	—	(623)
Future income tax expenses	(465)	—	(465)
Future net cash flows	2,473	—	2,473
10% annual discount for estimated timing of cash flows	(738)	—	(738)
Standardized measure of discounted future net cash flows	<u>\$ 1,735</u>	<u>\$ —</u>	<u>\$ 1,735</u>
Standardized measure of discontinued future net cash flows, including effects of hedging activities	<u>\$ 1,671</u>	<u>\$ —</u>	<u>\$ 1,671</u>

⁽¹⁾ United States excludes \$148 million, \$139 million and \$111 million of future net cash outflows attributable to hedging activities during 2004, 2003 and 2002.

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end 2004 prices of \$6.22 per MMBtu for natural gas and \$43.45 per barrel of oil. Adjustments for transportation and other charges resulted in a net price of \$5.83 per Mcf of natural gas, \$42.11 per Bbl of oil and \$31.64 per Bbl of NGL. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

We do not rely upon the standardized measure when making investment and operating decisions. These decisions are based on various factors including probable and proved reserves, different price and cost assumptions, actual economic conditions, capital availability and corporate investment criteria.

The following are the principal sources of change in the worldwide standardized measure of discounted future net cash flows:

	Years Ended December 31, ⁽¹⁾⁽²⁾		
	2004	2003	2002
	(In millions)		
Sales and transfers of natural gas and oil produced net of production costs	\$(567)	\$(677)	\$ (964)
Net changes in prices and production costs	159	598	1,888
Extensions, discoveries and improved recovery, less related costs	90	399	568
Changes in estimated future development costs	26	(24)	38
Previously estimated development costs incurred during the period	11	50	88
Revisions of previous quantity estimates	(122)	(118)	(367)
Accretion of discount	210	195	135
Net change in income taxes	31	19	(215)
Purchases of reserves in place	—	7	—
Sales of reserves in place	(11)	(336)	(1,122)
Changes in production rates, timing and other	(23)	53	332
Net change	<u>\$(196)</u>	<u>\$ 166</u>	<u>\$ 381</u>

⁽¹⁾ This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.

⁽²⁾ Includes operations in the United States and Brazil.

SCHEDULE II
EL PASO CGP COMPANY AND SUBSIDIARIES
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2004, 2003 and 2002
(In millions)

<u>Description</u>	<u>Balance at Beginning of Period</u>	<u>Charged to Costs and Expenses</u>	<u>Deductions</u>	<u>Charged to Other Accounts</u>	<u>Balance at End of Period</u>
2004					
Allowance for doubtful accounts	\$ 37	\$ (8)	\$ (8) ⁽³⁾	\$ 8	\$ 29
Valuation allowance on deferred tax assets	1	24 ⁽¹⁾	—	—	25
Legal reserves	27	7 ⁽⁷⁾	—	2	36
Environmental reserves	131	9	(18) ⁽⁴⁾	6	128
Regulatory reserves	—	—	—	—	—
2003					
Allowance for doubtful accounts	\$ 21	\$ (1)	\$ —	\$ 17	\$ 37
Valuation allowance on deferred tax assets	27	(26) ⁽¹⁾	—	—	1
Legal reserves	49	(3)	(16) ⁽⁴⁾	(3)	27
Environmental reserves	62	12	(10) ⁽⁴⁾	67 ⁽²⁾	131
Regulatory reserves	4	(3)	(1) ⁽⁴⁾	—	—
2002					
Allowance for doubtful accounts	\$ 23	\$ 1	\$ (7) ⁽³⁾	\$ 4	\$ 21
Valuation allowance on deferred tax assets	24	3	—	—	27
Legal reserves	51	11	(26) ⁽⁴⁾	13 ⁽⁵⁾	49
Environmental reserves	163	9	(16) ⁽⁴⁾	(94) ⁽⁶⁾	62
Regulatory reserves	5	7	(8) ⁽⁴⁾	—	4

- ⁽¹⁾ Relates primarily to foreign impairments and ceiling test charges and net operating loss carryovers.
⁽²⁾ Relates primarily to retained liabilities previously classified in our petroleum discontinued operations.
⁽³⁾ Relates primarily to accounts written off.
⁽⁴⁾ Relates primarily to payments for various litigation reserves, environmental remediation reserves and rate settlement reserves.
⁽⁵⁾ Relates to legal reserves previously embedded in environmental reserves.
⁽⁶⁾ In November 2002, we sold Coastal Mart, Inc. to an affiliate of El Paso which included environmental reserves of \$95 million.
⁽⁷⁾ These amounts primarily relate to additional liabilities recorded in connection with changes in our estimates of these liabilities. See Note 13 for a further discussion of this change.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2004, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our CEO and CFO, as appropriate, to allow timely discussion regarding required financial disclosure.

Based on the results of this evaluation, our CEO and CFO concluded that as a result of the material weaknesses discussed below, our disclosure controls and procedures were not effective as of December 31, 2004. Because of the material weaknesses, we performed additional procedures to ensure that our financial statements as of and for the year ended December 31, 2004, were fairly presented in all material respects in accordance with generally accepted accounting principles.

Internal Control Over Financial Reporting

During 2004, we continued our efforts to ensure our compliance with Section 404 of the Sarbanes-Oxley Act of 2002, which will apply to us at December 31, 2006. In our efforts to evaluate our internal control over financial reporting, we have identified the material weaknesses described below as of December 31, 2004. A material weakness is a control deficiency, or combination of control deficiencies, that results in a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

Access to Financial Application Programs and Data. At December 31, 2004, we did not maintain effective controls over access to financial application programs and data at each of our operating segments. Specifically, we identified internal control deficiencies with respect to inadequate design of and compliance with our security access procedures related to identifying and monitoring conflicting roles (i.e., segregation of duties) and a lack of independent monitoring of access to various systems by our information technology staff, as well as certain users that require unrestricted security access to financial and reporting systems to perform their responsibilities. These control deficiencies did not result in an adjustment to the 2004 interim or annual consolidated financial statements. However, these control deficiencies could result in a misstatement of a number of our financial statement accounts, including accounts receivable, property, plant and equipment, accounts payable, revenue, operating expenses, risk management assets and liabilities and potentially others, that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

Account Reconciliations. At December 31, 2004, we did not maintain effective controls over the preparation and review of account reconciliations. Specifically, we found various instances in our Power business where (1) account balances were not properly reconciled and (2) there was not consistent communication of reconciling differences within the organization to allow for adequate accumulation and resolution of reconciling items. These control deficiencies could result in a misstatement to a number of our financial statement accounts, including accounts receivable, other assets and liabilities, and taxes other than income taxes, that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

Identification, Capture and Communication of Financial Data Used in Accounting for Non-Routine Transactions or Activities. At December 31, 2004, we did not maintain effective controls related to identification, capture and communication of financial data used for accounting for non-routine transactions or activities. We identified control deficiencies related to the identification, capture and validation of pertinent information necessary to ensure the timely and accurate recording of non-routine transactions or activities, primarily related to accounting for investments in unconsolidated affiliates, determining impairment amounts, and accounting for divestiture of assets. These control deficiencies resulted in the restatement of our 2003 and 2004 consolidated financial statements and our related fourth quarter 2003 and first quarter 2004 financial information as described in the second paragraph of Note 1 as reported in this Form 10-K/A. Furthermore, these control deficiencies could result in a misstatement in the aforementioned accounts that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Accordingly, management has determined that these control deficiencies constitute a material weakness.

Changes in Internal Control over Financial Reporting

Changes in the Fourth Quarter 2004. There has been no change in our internal control over financial reporting during the fourth quarter of 2004 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Changes in 2005. Since December 31, 2004, we have taken action to correct the control deficiencies that resulted in the material weaknesses described above including implementing monitoring controls in our information technology areas over users who require unrestricted access to perform their job responsibilities and improving our account reconciliation processes. Other remedial actions have also been identified and are in the process of being implemented.

ITEM 9B. OTHER INFORMATION

None.

PART III

Item 10, "Directors and Executive Officers of the Registrant;" Item 11, "Executive Compensation;" Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters;" and Item 13, "Certain Relationships and Related Transactions," have been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Audit Fees

The Audit Fees for the years ended December 31, 2004 and 2003 of \$250,000 and \$300,000 were for professional services rendered by PricewaterhouseCoopers LLP for the audits of the consolidated financial statements of El Paso CGP Company.

All Other Fees

No other audit-related, tax or other services were provided by our independent registered public accounting firm for the years ended December 31, 2004 and 2003.

Policy for Approval of Audit and Non-Audit Fees

We are a wholly-owned direct subsidiary of El Paso and do not have a separate audit committee. El Paso's Audit Committee has adopted a pre-approval policy for audit and non-audit services. For a description of El Paso's pre-approval policies for audit and non-audit related services, see the El Paso proxy statement.

PART IV

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

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

1. Financial statements.

Our consolidated financial statements are included in Part II, Item 8 of this report:

	<u>Page</u>
Consolidated Statements of Income	45
Consolidated Balance Sheets	46
Consolidated Statements of Cash Flows	48
Consolidated Statements of Stockholder's Equity	50
Consolidated Statements of Comprehensive Income	51
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2. Financial statement schedules and supplementary information required to be submitted.

Schedule II — Valuation and Qualifying Accounts	106
Midland Cogeneration Venture Limited Partnership	
Report of Independent Registered Public Accounting Firm	110
Consolidated Balance Sheets	112
Consolidated Statements of Operations	113
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Javelina Company	
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Great Lakes Gas Transmission Limited Partnership	
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Consolidated Statements of Income and Partners' Capital	143
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Schedules other than those listed above are omitted because they are not applicable.

3. Exhibit list

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PRICEWATERHOUSECOOPERS LLP

Report of Independent Registered Public Accounting Firm

To the Partners and the Management Committee of
Midland Cogeneration Venture Limited Partnership:

We have completed an integrated audit of Midland Cogeneration Venture Limited Partnership 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its December 31, 2003 and December 31, 2002 financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, partners' equity and cash flows present fairly, in all material respects, the financial position of the Midland Cogeneration Limited Partnership (a Michigan limited partnership) and its subsidiaries (MCV) at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the MCV's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As explained in Note 2 to the financial statements, effective April 1, 2002, Midland Cogeneration Venture Limited Partnership changed its method of accounting for derivative and hedging activities in accordance with Derivative Implementation Group ("DIG") Issue C-16.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting (not presented herein), that the MCV maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the MCV maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The MCV's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the MCV's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Detroit, Michigan
February 25, 2005

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
CONSOLIDATED BALANCE SHEETS AS OF DECEMBER 31,
(In Thousands)

	2004	2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 125,781	\$ 173,651
Accounts and notes receivable — related parties	54,368	43,805
Accounts receivable	42,984	38,333
Gas inventory	17,509	20,298
Unamortized property taxes	18,060	17,672
Derivative assets	94,977	86,825
Broker margin accounts, and prepaid gas costs and expenses	13,147	8,101
Total current assets	366,826	388,685
PROPERTY, PLANT AND EQUIPMENT:		
Property, plant and equipment	2,466,944	2,463,931
Pipeline	21,432	21,432
Total property, plant and equipment	2,488,376	2,485,363
Accumulated depreciation	(1,062,821)	(991,556)
Net property, plant and equipment	1,425,555	1,493,807
OTHER ASSETS:		
Restricted investment securities held-to-maturity	139,410	139,755
Derivative assets non-current	24,337	18,100
Deferred financing costs, net of accumulated amortization of \$18,498 and \$17,285, respectively	6,467	7,680
Prepaid gas costs, spare parts deposit, materials and supplies	17,782	21,623
Total other assets	187,996	187,158
TOTAL ASSETS	\$ 1,980,377	\$2,069,650
LIABILITIES AND PARTNERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable and accrued liabilities	\$ 82,693	\$ 57,368
Gas supplier funds on deposit	19,613	4,517
Interest payable	47,738	53,009
Current portion of long-term debt	76,548	134,576
Total current liabilities	226,592	249,470
NON-CURRENT LIABILITIES:		
Long-term debt	942,097	1,018,645
Other	1,712	2,459
Total non-current liabilities	943,809	1,021,104
COMMITMENTS AND CONTINGENCIES (Notes 7 and 8)		
TOTAL LIABILITIES	1,170,401	1,270,574
PARTNERS' EQUITY	809,976	799,076
TOTAL LIABILITIES AND PARTNERS' EQUITY	\$ 1,980,377	\$2,069,650

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31,
(In Thousands)

	<u>2004</u>	<u>2003</u>	<u>2002</u>
OPERATING REVENUES:			
Capacity	\$ 405,415	\$ 404,681	\$ 404,713
Electric	225,154	162,093	177,569
Steam	<u>19,090</u>	<u>17,638</u>	<u>14,537</u>
Total operating revenues	<u>649,659</u>	<u>584,412</u>	<u>596,819</u>
OPERATING EXPENSES:			
Fuel costs	413,061	254,988	255,142
Depreciation	88,712	89,437	88,963
Operations	18,769	16,943	16,642
Maintenance	13,508	15,107	12,666
Property and single business taxes	28,834	30,040	27,087
Administrative, selling and general	<u>11,236</u>	<u>9,959</u>	<u>8,195</u>
Total operating expenses	<u>574,120</u>	<u>416,474</u>	<u>408,695</u>
OPERATING INCOME	<u>75,539</u>	<u>167,938</u>	<u>188,124</u>
OTHER INCOME (EXPENSE):			
Interest and other income	5,460	5,100	5,555
Interest expense	<u>(104,618)</u>	<u>(113,247)</u>	<u>(119,783)</u>
Total other income (expense), net	<u>(99,158)</u>	<u>(108,147)</u>	<u>(114,228)</u>
NET INCOME (LOSS) BEFORE CUMULATIVE			
EFFECT OF ACCOUNTING CHANGE	(23,619)	59,791	73,896
Cumulative effect of change in method of accounting for derivative option contracts (to April 1, 2002) (Note 2)	<u>—</u>	<u>—</u>	<u>58,131</u>
NET INCOME (LOSS)	<u>\$ (23,619)</u>	<u>\$ 59,791</u>	<u>\$ 132,027</u>

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY
FOR THE YEARS ENDED DECEMBER 31,
(In Thousands)

	<u>General Partners</u>	<u>Limited Partners</u>	<u>Total</u>
BALANCE, DECEMBER 31, 2001	\$468,972	\$ 82,740	\$551,712
Comprehensive Income			
Net Income	114,947	17,080	132,027
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period ...	33,311	4,950	38,261
Reclassification adjustments recognized in net income above	<u>10,717</u>	<u>1,593</u>	<u>12,310</u>
Total other comprehensive income	<u>44,028</u>	<u>6,543</u>	<u>50,571</u>
Total Comprehensive Income	<u>158,975</u>	<u>23,623</u>	<u>182,598</u>
BALANCE, DECEMBER 31, 2002	\$627,947	\$106,363	\$734,310
Comprehensive Income			
Net Income	52,056	7,735	59,791
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period ...	34,484	5,125	39,609
Reclassification adjustments recognized in net income above	<u>(30,153)</u>	<u>(4,481)</u>	<u>(34,634)</u>
Total other comprehensive income	<u>4,331</u>	<u>644</u>	<u>4,975</u>
Total Comprehensive Income	<u>56,387</u>	<u>8,379</u>	<u>64,766</u>
BALANCE, DECEMBER 31, 2003	\$684,334	\$114,742	\$799,076
Comprehensive Income			
Net Loss	(20,563)	(3,056)	(23,619)
Other Comprehensive Income			
Unrealized gain on hedging activities since beginning of period ...	62,292	9,256	71,548
Reclassification adjustments recognized in net income above	<u>(32,239)</u>	<u>(4,790)</u>	<u>(37,029)</u>
Total other comprehensive income	<u>30,053</u>	<u>4,466</u>	<u>34,519</u>
Total Comprehensive Income	<u>9,490</u>	<u>1,410</u>	<u>10,900</u>
BALANCE, DECEMBER 31, 2004	<u>\$693,824</u>	<u>\$116,152</u>	<u>\$809,976</u>

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31,
(In Thousands)

	<u>2004</u>	<u>2003</u>	<u>2002</u>
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	\$ (23,619)	\$ 59,791	\$ 132,027
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation and amortization.....	89,925	90,792	90,430
Cumulative effect of change in accounting principle	—	—	(58,131)
(Increase) decrease in accounts receivable	(15,214)	(1,211)	48,343
(Increase) decrease in gas inventory	2,789	(732)	133
(Increase) decrease in unamortized property taxes	(388)	683	(1,730)
(Increase) decrease in broker margin accounts and prepaid expenses	(5,046)	(4,778)	31,049
(Increase) decrease in derivative assets	20,130	4,906	(20,444)
(Increase) decrease in prepaid gas costs, materials and supplies	3,841	(8,704)	1,376
Increase (decrease) in accounts payable and accrued liabilities ..	25,775	(712)	8,774
Increase in gas supplier funds on deposit	15,096	4,517	—
Decrease in interest payable	(5,271)	(3,377)	(3,948)
Increase (decrease) in other non-current liabilities	(1,197)	311	(24)
Net cash provided by operating activities.....	<u>106,821</u>	<u>141,486</u>	<u>227,855</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Plant modifications and purchases of plant equipment	(20,460)	(33,278)	(29,529)
Maturity of restricted investment securities held-to-maturity	674,553	601,225	377,192
Purchase of restricted investment securities held-to-maturity	<u>(674,208)</u>	<u>(602,279)</u>	<u>(374,426)</u>
Net cash used in investing activities	<u>(20,115)</u>	<u>(34,332)</u>	<u>(26,763)</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayment of financing obligation	<u>(134,576)</u>	<u>(93,928)</u>	<u>(182,084)</u>
Net cash used in financing activities	<u>(134,576)</u>	<u>(93,928)</u>	<u>(182,084)</u>
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(47,870)	13,226	19,008
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	<u>173,651</u>	<u>160,425</u>	<u>141,417</u>
CASH AND EQUIVALENTS AT END OF PERIOD	<u>\$ 125,781</u>	<u>\$ 173,651</u>	<u>\$ 160,425</u>

The accompanying notes are an integral part of these statements.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) The Partnership and Associated Risks

MCV was organized to construct, own and operate a combined-cycle, gas-fired cogeneration facility (the "Facility") located in Midland, Michigan. MCV was formed on January 27, 1987, and the Facility began commercial operation in 1990.

In 1992, MCV had acquired the outstanding common stock of PVCO Corp., a previously inactive company. MCV and PVCO Corp. then entered into a partnership agreement to form MCV Gas Acquisition General Partnership ("MCV GAGP") for the purpose of buying and selling natural gas on the spot market and other transactions involving natural gas activities. PVCO Corp. and MCV GAGP were dissolved on January 30, 2004 and July 2, 2004, respectively, due to inactivity.

The Facility has a net electrical generating capacity of approximately 1500 MW and approximately 1.5 million pounds of process steam capacity per hour. MCV has entered into three principal energy sales agreements. MCV has contracted to (i) supply up to 1240 MW of electric capacity ("Contract Capacity") to Consumers Energy Company ("Consumers") under the Power Purchase Agreement ("PPA"), for resale to its customers through 2025, (ii) supply electricity and steam to The Dow Chemical Company ("Dow") through 2008 and 2015, respectively, under the Steam and Electric Power Agreement ("SEPA") and (iii) supply steam to Dow Corning Corporation ("DCC") under the Steam Purchase Agreement ("SPA") through 2011. From time to time, MCV enters into other sales agreements for the sale of excess capacity and/or energy available above MCV's internal use and obligations under the PPA, SEPA and SPA. Results of operations are primarily dependent on successfully operating the Facility at or near contractual capacity levels and on Consumers' ability to perform its obligations under the PPA. Sales pursuant to the PPA have historically accounted for over 90% of MCV's revenues.

The PPA permits Consumers, under certain conditions, to reduce the capacity and energy charges payable to MCV and/or to receive refunds of capacity and energy charges paid to MCV if the Michigan Public Service Commission ("MPSC") does not permit Consumers to recover from its customers the capacity and energy charges specified in the PPA (the "regulatory-out" provision). Until September 15, 2007, however, the capacity charge may not be reduced below an average capacity rate of 3.77 cents per kilowatt-hour for the available Contract Capacity notwithstanding the "regulatory-out" provision. Consumers and MCV are required to support and defend the terms of the PPA.

The Facility is a qualifying cogeneration facility ("QF") originally certified by the Federal Energy Regulatory Commission ("FERC") under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). In order to maintain QF status, certain operating and efficiency standards must be maintained on a calendar-year basis and certain ownership limitations must be met. In the case of a topping-cycle generating plant such as the Facility, the applicable operating standard requires that the portion of total energy output that is put to some useful purpose other than facilitating the production of power (the "Thermal Percentage") be at least 5%. In addition, the Facility must achieve a PURPA efficiency standard (the sum of the useful power output plus one-half of the useful thermal energy output, divided by the energy input (the "Efficiency Percentage")) of at least 45%. If the Facility maintains a Thermal Percentage of 15% or higher, the required Efficiency Percentage is reduced to 42.5%. Since 1990, the Facility has achieved the applicable Thermal and Efficiency Percentages. For the twelve months ended December 31, 2004, the Facility achieved a Thermal Percentage of 15.6% and an Efficiency Percentage of 47.6%. The loss of QF status could, among other things, cause MCV to lose its rights under PURPA to sell power from the Facility to Consumers at Consumers' "avoided cost" and subject MCV to additional federal and state regulatory requirements.

The Facility is wholly dependent upon natural gas for its fuel supply and a substantial portion of the Facility's operating expenses consist of the costs of natural gas. MCV recognizes that its existing gas contracts are not sufficient to satisfy the anticipated gas needs over the term of the PPA and, as such, no assurance can be given as to the availability or price of natural gas after the expiration of the existing gas contracts. In

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

addition, to the extent that the costs associated with production of electricity rise faster than the energy charge payments, MCV's financial performance will be negatively affected. The extent of such impact will depend upon the amount of the average energy charge payable under the PPA, which is based upon costs incurred at Consumers' coal-fired plants and upon the amount of energy scheduled by Consumers for delivery under the PPA. However, given the unpredictability of these factors, the overall economic impact upon MCV of changes in energy charges payable under the PPA and in future fuel costs under new or existing contracts cannot accurately be predicted.

At both the state and federal level, efforts continue to restructure the electric industry. A significant issue to MCV is the potential for future regulatory denial of recovery by Consumers from its customers of above market PPA costs Consumers pays MCV. At the state level, the MPSC entered a series of orders from June 1997 through February 1998 (collectively the "Restructuring Orders"), mandating that utilities "wheel" third-party power to the utilities' customers, thus permitting customers to choose their power provider. MCV, as well as others, filed an appeal in the Michigan Court of Appeals to protect against denial of recovery by Consumers of PPA charges. The Michigan Court of Appeals found that the Restructuring Orders do not unequivocally disallow such recovery by Consumers and, therefore, MCV's issues were not ripe for appellate review and no actual controversy regarding recovery of costs could occur until 2008, at the earliest. In June 2000, the State of Michigan enacted legislation which, among other things, states that the Restructuring Orders (being voluntarily implemented by Consumers) are in compliance with the legislation and enforceable by the MPSC. The legislation provides that the rights of parties to existing contracts between utilities (like Consumers) and QFs (like MCV), including the rights to have the PPA charges recovered from customers of the utilities, are not abrogated or diminished, and permits utilities to securitize certain stranded costs, including PPA charges.

In 1999, the U.S. District Court granted summary judgment to MCV declaring that the Restructuring Orders are preempted by federal law to the extent they prohibit Consumers from recovering from its customers any charge for avoided costs (or "stranded costs") to be paid to MCV under PURPA pursuant to the PPA. In 2001, the United States Court of Appeals ("Appellate Court") vacated the U.S. District Court's 1999 summary judgment and ordered the case dismissed based upon a finding that no actual case or controversy existed for adjudication between the parties. The Appellate Court determined that the parties' dispute is hypothetical at this time and the QFs' (including MCV) claims are premised on speculation about how an order might be interpreted by the MPSC, in the future.

Two significant issues that could affect MCV's future financial performance are the price of natural gas and Consumers' ability/obligation to pay PPA charges. Natural gas prices have historically been volatile and presently there is no consensus among forecasters on the price or range of future prices of natural gas. Even with the approved Resource Conservation Agreement and Reduced Dispatch Agreement, if gas prices continue at present levels or increase, the economics of operating the Facility may be adversely affected. Consumers' ability/obligation to pay PPA charges may be affected by an MPSC order denying Consumers recovery from ratepayers. This issue is likely to be addressed in the timeframe of 2007 or beyond. MCV continues to monitor and participate in these matters as appropriate, and to evaluate potential impacts on both cash flows and recoverability of the carrying value of property, plant and equipment. MCV management cannot, at this time, predict the impact or outcome of these matters.

(2) Significant Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Following is a discussion of MCV's significant accounting policies.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Principles of Consolidation

The consolidated financial statements included the accounts of MCV and its wholly-owned subsidiaries, PVCO Corp. and MCV GAGP. Previously, all material transactions and balances among entities, which comprise MCV, had been eliminated in the consolidated financial statements. The 2004 dissolution of these wholly-owned subsidiaries had no impact on the financial position and results of operations.

Revenue Recognition

MCV recognizes revenue for the sale of variable energy and fixed energy when delivered. Capacity and other installment revenues are recognized based on plant availability or other contractual arrangements.

Fuel Costs

MCV's fuel costs are those costs associated with securing natural gas, transportation and storage services necessary to generate electricity and steam from the Facility. These costs are recognized in the income statement based upon actual volumes burned to produce the delivered energy. In addition, MCV engages in certain cost mitigation activities to offset the fixed charges MCV incurs for these activities. The gains or losses resulting from these activities have resulted in net gains of approximately \$6.7 million, \$7.7 million and \$3.9 million for the years ended 2004, 2003 and 2002, respectively. These net gains are reflected as a component of fuel costs.

In July 2000, in response to rapidly escalating natural gas prices and since Consumers' electric rates were frozen, MCV entered into a series of transactions with Consumers whereby Consumers agreed to reduce MCV's dispatch level and MCV agreed to share with Consumers the savings realized by not having to generate electricity ("Dispatch Mitigation"). On January 1, 2004, Dispatch Mitigation ceased and Consumers began dispatching MCV pursuant to a 915 MW settlement and a 325 MW settlement "availability caps" provision (i.e., minimum dispatch of 1100 MW on- and off-peak ("Forced Dispatch")). In 2004, MCV and Consumers entered into a Resource Conservation Agreement ("RCA") and a Reduced Dispatch Agreement ("RDA") which, among other things, provides that Consumers will economically dispatch MCV, if certain conditions are met. Such dispatch is expected to reduce electric production from what is occurring under the Forced Dispatch, as well as decrease gas consumption by MCV. The RCA provides that Consumers has a right of first refusal to purchase, at market prices, the gas conserved under the RCA. The RCA and RDA provide for the sharing of savings realized by not having to generate electricity. The RCA and RDA were approved by an order of the MPSC on January 25, 2005 and MCV and Consumers accepted the terms of the MPSC order making the RCA and RDA effective as of January 27, 2005. This MPSC order is subject to appeal by other parties. MCV management cannot predict the final outcome of any such appeal. While awaiting approval of this order, effective October 23, 2004, MCV and Consumers entered into an interim Dispatch Mitigation program for energy dispatch above 1100 MW up to 1240 MW of Contract Capacity under the PPA. This interim program, which was structured very similarly to the RCA and RDA, was terminated on January 27, 2005 with the effective date of the RCA/RDA. For the twelve months ended December 31, 2004, 2003 and 2002, MCV estimates that these programs have resulted in net savings of approximately \$1.6 million, \$13.0 million and \$2.5 million, a portion of which is realized in reduced maintenance expenditures in future years.

Accounts Receivable

Accounts receivable and accounts receivable-related parties are recorded at the billed amount and do not bear interest. MCV evaluates the need for an allowance for doubtful accounts using MCV's best estimate of the amount of probable credit losses. At December 31, 2004 and 2003, no allowance was provided since typically all receivables are collected within 30 days of each month end.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Inventory

MCV's inventory of natural gas is stated at the lower of cost or market, and valued using the last-in, first-out ("LIFO") method. Inventory includes the costs of purchased gas, variable transportation and storage. The amount of reserve to reduce inventories from first-in, first-out ("FIFO") basis to the LIFO basis at December 31, 2004 and 2003, was \$10.3 million and \$8.4 million, respectively. Inventory cost, determined on a FIFO basis, approximates current replacement cost.

Materials and Supplies

Materials and supplies are stated at the lower of cost or market using the weighted average cost method. The majority of MCV's materials and supplies are considered replacement parts for MCV's Facility.

Depreciation

Original plant, equipment and pipeline were valued at cost for the constructed assets and at the asset transfer price for purchased and contributed assets, and are depreciated using the straight-line method over an estimated useful life of 35 years, which is the term of the PPA, except for the hot gas path components of the GTGs which are primarily being depreciated over a 25-year life. Plant construction and additions, since commercial operations in 1990, are depreciated using the straight-line method over the remaining life of the plant which currently is 22 years. Major renewals and replacements, which extend the useful life of plant and equipment are capitalized, while maintenance and repairs are expensed when incurred. Major equipment overhauls are capitalized and amortized to the next equipment overhaul. Personal property is depreciated using the straight-line method over an estimated useful life of 5 to 15 years. The cost of assets and related accumulated depreciation are removed from the accounts when sold or retired, and any resulting gain or loss reflected in operating income.

Federal Income Tax

MCV is not subject to Federal or State income taxes. Partnership earnings are taxed directly to each individual partner.

Statement of Cash Flows

All liquid investments purchased with a maturity of three months or less at time of purchase are considered to be current cash equivalents.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents and short-term investments approximate fair value because of the short maturity of these instruments. MCV's short-term investments, which are made up of investment securities held-to-maturity, as of December 31, 2004 and December 31, 2003 have original maturity dates of approximately one year or less. The unique nature of the negotiated financing obligation discussed in Note 6 makes it unnecessary to estimate the fair value of the Owner Participants' underlying debt and equity instruments supporting such financing obligation, since SFAS No. 107 "Disclosures about Fair Value of Financial Instruments" does not require fair value accounting for the lease obligation.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2001, MCV adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" which was issued in June 1998 and then amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities — Deferral of the Effective Date of SFAS No. 133," SFAS No. 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities — An

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

amendment of FASB Statement No. 133” and SFAS No. 149 “Amendment of Statement 133 on Derivative Instruments and Hedging Activity (collectively referred to as “SFAS No. 133”). SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in a derivative’s fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges in some cases allows a derivative’s gains and losses to offset related results on the hedged item in the income statement or permits recognition of the hedge results in other comprehensive income, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting.

Electric Sales Agreements

MCV believes that its electric sales agreements currently do not qualify as derivatives under SFAS No. 133, due to the lack of an active energy market (as defined by SFAS No. 133) in the State of Michigan and the transportation cost to deliver the power under the contracts to the closest active energy market at the Cinergy hub in Ohio and as such does not record the fair value of these contracts on its balance sheet. If an active energy market emerges, MCV intends to apply the normal purchase, normal sales exception under SFAS No. 133 to its electric sales agreements, to the extent such exception is applicable.

Natural Gas Supply Contracts

MCV management believes that its long-term natural gas contracts, which do not contain volume optionality, qualify under SFAS No. 133 for the normal purchases and normal sales exception. Therefore, these contracts are currently not recognized at fair value on the balance sheet.

The FASB issued DIG Issue C-16, which became effective April 1, 2002, regarding natural gas commodity contracts that combine an option component and a forward component. This guidance requires either that the entire contract be accounted for as a derivative or the components of the contract be separated into two discrete contracts. Under the first alternative, the entire contract considered together would not qualify for the normal purchases and sales exception under the revised guidance. Under the second alternative, the newly established forward contract could qualify for the normal purchases and sales exception, while the option contract would be treated as a derivative under SFAS No. 133 with changes in fair value recorded through earnings. At April 1, 2002, MCV had nine long-term gas contracts that contained both an option and forward component. As such, they were no longer accounted for under the normal purchases and sales exception and MCV began mark-to-market accounting of these nine contracts through earnings. As of January 31, 2005, only four contracts of the original nine contracts, which contained an option and forward component remain in effect. In addition, as a result of implementing the RCA/RDA, effective January 27, 2005, MCV has determined that as of the effective date of the RCA/RDA, an additional nine long term contracts (for a total of 13) will no longer be accounted for under the normal purchases and sales exception, per SFAS No. 133 and will result in additional mark-to-market activity in 2005 and beyond. MCV expects future earnings volatility on both the remaining long term gas contracts that contain volume optionality as well as the long term gas contracts under the RCA/RDA that will require mark-to-market recognition on a quarterly basis.

Based on the natural gas prices, at the beginning of April 2002, MCV recorded a \$58.1 million gain for the cumulative effect of this accounting change. From April 2002 to December 2004, MCV recorded an additional net mark-to-market loss of \$2.3 million for these gas contracts. The cumulative mark-to-market gain through December 31, 2004 of \$55.8 million is recorded as a current and non-current derivative asset on the balance sheet, as detailed below. These assets will reverse over the remaining life of these gas contracts, ranging from 2005 to 2007. For the twelve months ended December 31, 2004 and 2003, MCV recorded in “Fuel costs” losses of \$19.2 million and \$5.0 million, respectively, for net mark-to-market adjustments

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

associated with these contracts. In addition, as of December 31, 2004 and 2003, MCV recorded “Derivative assets” in Current Assets in the amount of \$31.4 million and \$56.9 million, respectively, and for the same periods recorded “Derivative assets non-current” in Other Assets in the amount of \$24.3 million and \$18.1 million, respectively, representing the mark-to-market value on these long-term natural gas contracts.

Natural Gas Supply Futures and Options

To manage market risks associated with the volatility of natural gas prices, MCV maintains a gas hedging program. MCV enters into natural gas futures contracts, option contracts, and over the counter swap transactions (“OTC swaps”) in order to hedge against unfavorable changes in the market price of natural gas in future months when gas is expected to be needed. These financial instruments are being utilized principally to secure anticipated natural gas requirements necessary for projected electric and steam sales, and to lock in sales prices of natural gas previously obtained in order to optimize MCV’s existing gas supply, storage and transportation arrangements.

These financial instruments are derivatives under SFAS No. 133 and the contracts that are utilized to secure the anticipated natural gas requirements necessary for projected electric and steam sales qualify as cash flow hedges under SFAS No. 133, since they hedge the price risk associated with the cost of natural gas. MCV also engages in cost mitigation activities to offset the fixed charges MCV incurs in operating the Facility. These cost mitigation activities include the use of futures and options contracts to purchase and/or sell natural gas to maximize the use of the transportation and storage contracts when it is determined that they will not be needed for Facility operation. Although these cost mitigation activities do serve to offset the fixed monthly charges, these cost mitigation activities are not considered a normal course of business for MCV and do not qualify as hedges under SFAS No. 133. Therefore, the resulting mark-to-market gains and losses from cost mitigation activities are flowed through MCV’s earnings.

Cash is deposited with the broker in a margin account at the time futures or options contracts are initiated. The change in market value of these contracts requires adjustment of the margin account balances. The margin account balance as of December 31, 2004 and 2003 was recorded as a current asset in “Broker margin accounts and prepaid expenses,” in the amount of \$1.4 million and \$4.1 million, respectively.

For the twelve months ended December 31, 2004, MCV has recognized in other comprehensive income, an unrealized \$34.5 million increase on the futures contracts and OTC swaps, which are hedges of forecasted purchases for plant use of market priced gas. This resulted in a net \$65.8 million gain in other comprehensive income as of December 31, 2004. This balance represents natural gas futures, options and OTC swaps with maturities ranging from January 2005 to December 2009, of which \$33.4 million of this gain is expected to be reclassified into earnings within the next twelve months. MCV also has recorded, as of December 31, 2004, a \$63.6 million current derivative asset in “Derivative assets,” representing the mark-to-market gain on natural gas futures for anticipated projected electric and steam sales accounted for as hedges. In addition, for the twelve months ended December 31, 2004, MCV has recorded a net \$36.5 million gain in earnings from hedging activities related to MCV natural gas requirements for Facility operations and a net \$1.8 million gain in earnings from cost mitigation activities.

For the twelve months ended December 31, 2003, MCV recognized an unrealized \$5.0 million increase in other comprehensive income on the futures contracts, which are hedges of forecasted purchases for plant use of market priced gas, which resulted in a \$31.3 million gain balance in other comprehensive income as of December 31, 2003. As of December 31, 2003, MCV had recorded a \$29.9 million current derivative asset in “Derivative assets.” For the twelve months ended December 31, 2003, MCV had recorded a net \$35.0 million gain in earnings from hedging activities related to MCV natural gas requirements for Facility operations and a net \$1.0 million gain in earnings from cost mitigation activities.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

New Accounting Standard

In 2003, the Emerging Issues Task Force (“EITF”) issued EITF 03-1 “The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments”. EITF 03-1 addresses how to determine the meaning of other-than-temporary impairment of certain debt and equity securities, the measurement of an impairment loss and accounting and disclosure considerations subsequent to the recognition of an other-than-temporary impairment. The various sections of EITF 03-1 became effective at various times during 2004. MCV has adopted this guidance and does not expect the application to materially affect its financial position or results of operations, since MCV’s investments approximate fair value due to the short maturity of its permitted investments.

(3) Restricted Investment Securities Held-to-Maturity

Non-current restricted investment securities held-to-maturity have carrying amounts that approximate fair value because of the short maturity of these instruments and consist of the following at December 31 (in thousands):

	<u>2004</u>	<u>2003</u>
Funds restricted for rental payments pursuant to the Overall Lease Transaction	\$138,150	\$137,296
Funds restricted for management non-qualified plans	<u>1,260</u>	<u>2,459</u>
Total	<u>\$139,410</u>	<u>\$139,755</u>

(4) Accounts Payable and Accrued Liabilities

Accounts payable and accrued liabilities consist of the following at December 31 (in thousands):

	<u>2004</u>	<u>2003</u>
Accounts payable		
Related parties	\$12,772	\$ 7,386
Trade creditors	53,476	34,786
Property and single business taxes	11,833	12,548
Other	<u>4,612</u>	<u>2,648</u>
Total	<u>\$82,693</u>	<u>\$57,368</u>

(5) Gas Supplier Funds on Deposit

Pursuant to individual gas contract terms with counterparties, deposit amounts or letters of credit may be required by one party to the other based upon the net amount of exposure. The net amount of exposure will vary with changes in market prices, credit provisions and various other factors. Collateral paid or received will be posted by one party to the other based on the net amount of the exposure. Interest is earned on funds on deposit. As of December 31, 2004, MCV is supplying credit support to two gas suppliers; one in the form of a letter of credit in the amount of \$2.4 million; and cash on deposit with the other in the amount of \$7.3 million. As of December 31, 2004, MCV is holding \$19.6 million of cash on deposit from two of MCV’s brokers. In addition as of December 31, 2004, MCV is also holding letters of credit totaling \$208.6 million from two gas suppliers, of which \$184.0 million is a letter of credit from El Paso Corporation (“El Paso”), a related party.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(6) Long-Term Debt

Long-term debt consists of the following at December 31 (in thousands):

	2004	2003
Financing obligation, maturing through 2015, payable in semi-annual installments of principal and interest, collateralized by property, plant and equipment	\$1,018,645	\$1,153,221
Less current portion	(76,548)	(134,576)
Total long-term debt	\$ 942,097	\$1,018,645

Financing Obligation

In June 1990, MCV obtained permanent financing for the Facility by entering into sale and leaseback agreements (“Overall Lease Transaction”) with a lessor group, related to substantially all of MCV’s fixed assets. Proceeds of the financing were used to retire borrowings outstanding under existing loan commitments, make a capital distribution to the Partners and retire a portion of notes issued by MCV to MEC Development Corporation (“MDC”) in connection with the transfer of certain assets by MDC to MCV. In accordance with SFAS No. 98, “Accounting For Leases,” the sale and leaseback transaction has been accounted for as a financing arrangement.

The financing obligation utilizes the effective interest rate method, which is based on the minimum lease payments required through the end of the basic lease term of 2015 and management’s estimate of additional anticipated obligations after the end of the basic lease term. The effective interest rate during the remainder of the basic lease term is approximately 9.4%.

Under the terms of the Overall Lease Transaction, MCV sold undivided interests in all of the fixed assets of the Facility for approximately \$2.3 billion, to five separate owner trusts (“Owner Trusts”) established for the benefit of certain institutional investors (“Owner Participants”). U.S. Bank National Association (formerly known as State Street Bank and Trust Company) serves as owner trustee (“Owner Trustee”) under each of the Owner Trusts, and leases undivided interests in the Facility on behalf of the Owner Trusts to MCV for an initial term of 25 years. CMS Midland Holdings Company (“CMS Holdings”), currently a wholly owned subsidiary of Consumers, acquired a 35% indirect equity interest in the Facility through its purchase of an interest in one of the Owner Trusts.

The Overall Lease Transaction requires MCV to achieve certain rent coverage ratios and other financial tests prior to a distribution to the Partners. Generally, these financial tests become more restrictive with the passage of time. Further, MCV is restricted to making permitted investments and incurring permitted indebtedness as specified in the Overall Lease Transaction. The Overall Lease Transaction also requires filing of certain periodic operating and financial reports, notification to the lessors of events constituting a material adverse change, significant litigation or governmental investigation, and change in status as a qualifying facility under FERC proceedings or court decisions, among others. Notification and approval is required for plant modification, new business activities, and other significant changes, as defined. In addition, MCV has agreed to indemnify various parties to the sale and leaseback transaction against any expenses or environmental claims asserted, or certain federal and state taxes imposed on the Facility, as defined in the Overall Lease Transaction.

Under the terms of the Overall Lease Transaction and refinancing of the tax-exempt bonds, approximately \$25.0 million of transaction costs were a liability of MCV and have been recorded as a deferred cost. Financing costs incurred with the issuance of debt are deferred and amortized using the interest method over the remaining portion of the 25-year lease term. Deferred financing costs of approximately \$1.2 million, \$1.4 million and \$1.5 million were amortized in the years 2004, 2003 and 2002, respectively.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Interest and fees incurred related to long-term debt arrangements during 2004, 2003 and 2002 were \$103.4 million, \$111.9 million and \$118.3 million, respectively.

Interest and fees paid during 2004, 2003 and 2002 were \$108.6 million, \$115.4 million and \$122.1 million, respectively.

Minimum payments due under these long-term debt arrangements over the next five years are (in thousands):

	<u>Principal</u>	<u>Interest</u>	<u>Total</u>
2005	\$ 76,548	\$ 97,835	\$174,383
2006	63,459	92,515	155,974
2007	62,916	87,988	150,904
2008	67,753	83,163	150,916
2009	<u>70,335</u>	<u>76,755</u>	<u>147,090</u>
	<u>\$341,011</u>	<u>\$438,256</u>	<u>\$779,267</u>

Revolving Credit Agreement

MCV has also entered into a working capital line (“Working Capital Facility”), which expires August 27, 2005. Under the terms of the existing agreement, MCV can borrow up to the \$50.0 million commitment, in the form of short-term borrowings or letters of credit collateralized by MCV’s natural gas inventory and earned receivables. At any given time, borrowings and letters of credit are limited by the amount of the borrowing base, defined as 90% of earned receivables and 50% of natural gas inventory, capped at \$15 million. MCV did not utilize the Working Capital Facility during the year 2004, except for letters of credit associated with normal business practices. At December 31, 2004, MCV had \$47.6 million available under its Working Capital Facility. As of December 31, 2004, MCV’s borrowing base was capped at the maximum amount available of \$50.0 million and MCV had outstanding letters of credit in the amount of \$2.4 million. MCV believes that amounts available to it under the Working Capital Facility along with available cash reserves will be sufficient to meet any working capital shortfalls that might occur in the near term.

Intercreditor Agreement

MCV has also entered into an Intercreditor Agreement with the Owner Trustee, Working Capital Lender, U.S. Bank National Association as Collateral Agent (“Collateral Agent”) and the Senior and Subordinated Indenture Trustees. Under the terms of this agreement, MCV is required to deposit all revenues derived from the operation of the Facility with the Collateral Agent for purposes of paying operating expenses and rent. In addition, these funds are required to pay construction modification costs and to secure future rent payments. As of December 31, 2004, MCV has deposited \$138.2 million into the reserve account. The reserve account is to be maintained at not less than \$40 million nor more than \$137 million (or debt portion of next succeeding basic rent payment, whichever is greater). Excess funds in the reserve account are periodically transferred to MCV. This agreement also contains provisions governing the distribution of revenues and rents due under the Overall Lease Transaction, and establishes the priority of payment among the Owner Trusts, creditors of the Owner Trusts, creditors of MCV and the Partnership.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(7) Commitments and Other Agreements

MCV has entered into numerous commitments and other agreements related to the Facility. Principal agreements are summarized as follows:

Power Purchase Agreement

MCV and Consumers have executed the PPA for the sale to Consumers of a minimum amount of electricity, subject to the capacity requirements of Dow and any other permissible electricity purchasers. Consumers has the right to terminate and/or withhold payment under the PPA if the Facility fails to achieve certain operating levels or if MCV fails to provide adequate fuel assurances. In the event of early termination of the PPA, MCV would have a maximum liability of approximately \$270 million if the PPA were terminated in the 12th through 24th years. The term of this agreement is 35 years from the commercial operation date and year-to-year thereafter.

Steam and Electric Power Agreement

MCV and Dow executed the SEPA for the sale to Dow of certain minimum amounts of steam and electricity for Dow's facilities.

If the SEPA is terminated, and Consumers does not fulfill MCV's commitments as provided in the Backup Steam and Electric Power Agreement, MCV will be required to pay Dow a termination fee, calculated at that time, ranging from a minimum of \$60 million to a maximum of \$85 million. This agreement provides for the sale to Dow of steam and electricity produced by the Facility for terms of 25 years and 15 years, respectively, commencing on the commercial operation date and year-to-year thereafter.

Steam Purchase Agreement

MCV and DCC executed the SPA for the sale to DCC of certain minimum amounts of steam for use at the DCC Midland site. Steam sales under the SPA commenced in July 1996. Termination of this agreement, prior to expiration, requires the terminating party to pay to the other party a percentage of future revenues, which would have been realized had the initial term of 15 years been fulfilled. The percentage of future revenues payable is 50% if termination occurs prior to the fifth anniversary of the commercial operation date and 33 $\frac{1}{3}$ % if termination occurs after the fifth anniversary of this agreement. The term of this agreement is 15 years from the commercial operation date of steam deliveries under the contract and year-to-year thereafter.

Gas Supply Agreements

MCV has entered into gas purchase agreements with various producers for the supply of natural gas. The current contracted volume totals 238,531 MMBtu per day annual average for 2005. As of January 1, 2005, gas contracts with U.S. suppliers provide for the purchase of 173,336 MMBtu per day while gas contracts with Canadian suppliers provide for the purchase of 65,195 MMBtu per day. Some of these contracts require MCV to pay for a minimum amount of natural gas per year, whether or not taken. The estimated minimum commitments under these contracts based on current long term prices for gas for the years 2005 through 2009 are \$384.6 million, \$402.1 million, \$436.7 million, \$358.8 million and \$324.0 million, respectively. A portion of these payments may be utilized in future years to offset the cost of quantities of natural gas taken above the minimum amounts.

Gas Transportation Agreements

MCV has entered into firm natural gas transportation agreements with various pipeline companies. These agreements require MCV to pay certain reservation charges in order to reserve the transportation capacity.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

MCV incurred reservation charges in 2004, 2003 and 2002, of \$35.5 million, \$34.8 million and \$35.1 million, respectively. The estimated minimum reservation charges required under these agreements for each of the years 2005 through 2009 are \$34.3 million, \$30.0 million, \$21.6 million, \$21.6 million and \$21.6 million, respectively. These projections are based on current commitments.

Gas Turbine Service Agreements

Under a Service Agreement, as amended, with Alstom, which commenced on January 1, 1990 and was set to expire upon the earlier of the completion of the sixth series of major GTG inspections or December 31, 2009, Alstom sold MCV an initial inventory of spare parts for the GTGs and provided qualified service personnel and supporting staff to assist MCV, to perform scheduled inspections on the GTGs, and to repair the GTGs at MCV's request. The Service Agreement was terminated for cause by MCV in February 2004. Alstom disputed MCV's right to terminate for cause. The parties settled the dispute and the agreement terminated in February 2004. MCV has a maintenance service and parts agreement with General Electric International, Inc. ("GEII"), which commenced July 1, 2004 ("GEII Agreement"). GEII will provide maintenance services and hot gas path parts for MCV's twelve GTGs, including providing an initial inventory of spare parts for the GTGs and providing qualified service personnel and supporting staff to assist MCV, to perform scheduled inspections on the GTGs, and to repair the GTGs at MCV's request. Under terms and conditions similar to the MCV/Alstom Service Agreement, as described above the GEII Agreement will cover four rounds of major GTG inspections, which are expected to be completed by the year 2015, at a savings to MCV as compared to the Service Agreement with Alstom. MCV is to make monthly payments over the life of the contract totaling approximately \$207 million (subject to escalations based on defined indices). The GEII Agreement can be terminated by either party for cause or convenience. Should termination for convenience occur, a buy out amount will be paid by the terminating party with payments ranging from approximately \$19.0 million to \$.9 million, based upon the number of operating hours utilized since commencement of the GEII Agreement.

Steam Turbine Service Agreement

MCV entered into a nine year Steam Turbine Maintenance Agreement with General Electric Company effective January 1, 1995, which is designed to improve unit reliability, increase availability and minimize unanticipated maintenance costs. In addition, this contract includes performance incentives and penalties, which are based on the length of each scheduled outage and the number of forced outages during a calendar year. Effective February 1, 2004, MCV and GE amended this contract to extend its term through August 31, 2007. MCV will continue making monthly payments over the life of the contract, which will total \$22.3 million (subject to escalation based on defined indices). The parties have certain termination rights without incurring penalties or damages for such termination. Upon termination, MCV is only liable for payment of services rendered or parts provided prior to termination.

Site Lease

In December 1987, MCV leased the land on which the Facility is located from Consumers ("Site Lease"). MCV and Consumers amended and restated the Site Lease to reflect the creation of five separate undivided interests in the Site Lease as of June 1, 1990. Pursuant to the Overall Lease Transaction, MCV assigned these undivided interests in the Site Lease to the Owner Trustees, which in turn subleased the undivided interests back to MCV under five separate site subleases.

The Site Lease is for a term which commenced on December 29, 1987, and ends on December 31, 2035, including two renewal options of five years each. The rental under the Site Lease is \$.6 million per annum, including the two five-year renewal terms.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

(8) Contingencies

Property Taxes

In 1997, MCV filed a property tax appeal against the City of Midland at the Michigan Tax Tribunal contesting MCV's 1997 property taxes. Subsequently, MCV filed appeals contesting its property taxes for tax years 1998 through 2004 at the Michigan Tax Tribunal. A trial was held for tax years 1997-2000. The appeals for tax years 2001-2004 are being held in abeyance. On January 23, 2004, the Michigan Tax Tribunal issued its decision in MCV's tax appeal against the City of Midland for tax years 1997 through 2000 and has issued several orders correcting errors in the initial decision (together the "MTT Decision"). MCV management has estimated that the MTT Decision will result in a refund to MCV for the tax years 1997 through 2000 of at least approximately \$35.3 million in taxes plus \$9.6 million of interest as of December 31, 2004. The MTT Decision has been appealed to the Michigan Appellate Court by the City of Midland. MCV has filed a cross-appeal at the Michigan Appellate Court. MCV management cannot predict the outcome of these legal proceedings. MCV has not recognized any of the above stated refunds (net of approximately \$16.1 million of deferred expenses) in earnings at this time.

NOx Allowances

The United States Environmental Protection Agency ("US EPA") has approved the State of Michigan's — State Implementation Plan ("SIP"), which includes an interstate NOx budget and allowance trading program administered by the US EPA beginning in 2004. Each NOx allowance permits a source to emit one ton of NOx during the seasonal control period, which for 2004 was from May 31 through September 30. NOx allowances may be bought or sold and unused allowances may be "banked" for future use, with certain limitations. MCV estimates that it will have excess NOx allowances to sell under this program. Consumers has given notice to MCV that it believes the ownership of the NOx allowances under this program belong, at least in part, to Consumers. MCV has initiated the dispute resolution process pursuant to the PPA to resolve this issue and the parties have entered into a standstill agreement deferring the resolution of this dispute. However, either party may terminate the standstill agreement at any time and reinstate the PPA's dispute resolution provisions. MCV management cannot predict the outcome of this issue. As of December 31, 2004, MCV has sold 1,200 tons of 2004 allowances for \$2.7 million, which is recorded in "Accounts payable and accrued liabilities", pending resolution of ownership of these credits.

Environmental Issues

On July 12, 2004 the Michigan Department of Environmental Quality ("DEQ"), Air Quality Division, issued MCV a "Letter of Violation" asserting that MCV violated its Air Use Permit to Install No. 209-02 ("PTI") by exceeding the carbon monoxide emission limit on the Unit 14 GTG duct burner and failing to maintain certain records in the required format. On July 13, 2004 the DEQ, Water Division, issued MCV a "Notice Letter" asserting MCV violated its National Pollutant Discharge Elimination System Permit by discharging heated process waste water into the storm water system, failure to document inspections, and other minor infractions ("alleged NPDES violations").

MCV has declared all duct burners as unavailable for operational use (which reduces the generation capability of the Facility by approximately 100 MW) and is assessing the duct burner issue and has begun other corrective action to address the DEQ's assertions. MCV disagrees with certain of the DEQ's assertions. MCV filed responses to these DEQ letters in July and August 2004. On December 13, 2004, the DEQ informed MCV that it was pursuing an escalated enforcement action against MCV regarding the alleged violations of MCV's PTI. The DEQ also stated that the alleged violations are deemed federally significant and, as such, placed MCV on the United States Environmental Protection Agency's High Priority Violators List ("HPVL"). The DEQ and MCV are pursuing voluntary settlement of this matter, which will satisfy state and federal requirements and remove MCV from the HPVL. Any such settlement is likely to involve a fine,

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

but the DEQ has not, at this time, stated what, if any, fine they will seek to impose. At this time, MCV management cannot predict the financial impact or outcome of these issues, however, MCV believes it has resolved all issues associated with the alleged NPDES violations and does not expect any further MDEQ actions on this NPDES matter.

(9) Voluntary Severance Program

In July 2004, MCV announced a Voluntary Severance Program (“VSP”) for all employees (union and non-union employees), subject to certain eligibility requirements. The VSP entitled participating employees, upon termination, to a lump sum payment, based upon number of years of service up to a maximum of 52 weeks of wages. Nineteen employees elected to participate in the VSP and MCV has recorded \$1.7 million of severance costs in “Operating Expenses” related to the nineteen employees.

(10) Retirement Benefits

Postretirement Health Care Plans

In 1992, MCV established defined cost postretirement health care plans (“Plans”) that cover all full-time employees, excluding key management. The Plans provide health care credits, which can be utilized to purchase medical plan coverage and pay qualified health care expenses. Participants become eligible for the benefits if they retire on or after the attainment of age 65 or upon a qualified disability retirement, or if they have 10 or more years of service and retire at age 55 or older. The Plans granted retroactive benefits for all employees hired prior to January 1, 1992. This prior service cost has been amortized to expense over a five-year period. MCV annually funds the current year service and interest cost as well as amortization of prior service cost to both qualified and non-qualified trusts. The MCV accounts for retiree medical benefits in accordance with SFAS 106, “Employers Accounting for Postretirement Benefits Other Than Pensions.” This standard required the full accrual of such costs during the years that the employee renders service to the MCV until the date of full eligibility. The accumulated benefit obligation of the Plans were \$4.9 million at December 31, 2004 and \$3.3 million at December 31, 2003. The measurement date of these Plans was December 31, 2004.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the “Act”) was signed into law in December 2003. The Act expanded Medicare to include, for the first time, coverage for prescription drugs. At December 31, 2003, based upon FASB staff position, SFAS No. 106-1, “Employers Accounting for Postretirement Benefits Other Than Pensions,” MCV had elected to defer financial recognition of this legislation until issuance of final accounting guidance. The final SFAS No. 106-2 was issued in second quarter 2004 and supersedes SFAS No. 106-1, which MCV adopted during this same period. The adoption of this standard had no impact to MCV’s financial position because MCV does not consider its Plans to be actuarially equivalent. The Plans benefits provided to eligible participants are not annual or on-going in nature, but are a readily exhaustible, lump-sum amount available for use at the discretion of the participant.

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

The following table reconciles the change in the Plans' benefit obligation and change in Plan assets as reflected on the balance sheet as of December 31 (in thousands):

	<u>2004</u>	<u>2003</u>
<u>Change in benefit obligation:</u>		
Benefit obligation at beginning of year	\$ 3,276.0	\$2,741.9
Service cost	232.1	212.5
Interest cost	174.8	178.2
Actuarial gain (loss)	1,298.0	147.4
Benefits paid during year	<u>(8.3)</u>	<u>(4.0)</u>
Benefit obligation at end of year	<u>4,972.6</u>	<u>3,276.0</u>
<u>Change in Plan assets:</u>		
Fair value of Plan assets at beginning of year	2,826.8	2,045.8
Actual return on Plan assets	292.7	527.5
Employer contribution	206.5	257.5
Benefits paid during year	<u>(8.3)</u>	<u>(4.0)</u>
Fair value of Plan assets at end of year	<u>3,317.7</u>	<u>2,826.8</u>
Unfunded (funded) status	1,654.9	449.2
Unrecognized prior service cost	(155.9)	(170.3)
Unrecognized net gain (loss)	<u>(1,499.0)</u>	<u>(278.9)</u>
Accrued benefit cost	<u>\$ —</u>	<u>\$ —</u>

Net periodic postretirement health care cost for years ending December 31, included the following components (in thousands):

	<u>2004</u>	<u>2003</u>	<u>2002</u>
<u>Components of net periodic benefit cost:</u>			
Service cost	\$ 232.1	\$ 212.5	\$ 197.3
Interest cost	174.8	178.2	188.7
Expected return on Plan assets	(216.1)	(163.7)	(167.0)
Amortization of unrecognized net (gain) or loss	<u>15.7</u>	<u>30.5</u>	<u>14.3</u>
Net periodic benefit cost	<u>\$ 206.5</u>	<u>\$ 257.5</u>	<u>\$ 233.3</u>

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects (in thousands):

	<u>1-Percentage- Point Increase</u>	<u>1-Percentage Point Decrease</u>
Effect on total of service and interest cost components	\$ 51.6	\$ 44.7
Effect on postretirement benefit obligation	\$514.8	\$447.1

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

Assumptions used in accounting for the Post-Retirement Health Care Plan were as follows:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
Discount rate	5.75%	6.00%	6.75%
Long-term rate of return on Plan assets	8.00%	8.00%	8.00%
Inflation benefit amount			
1998 through 2004	0.00%	0.00%	0.00%
2005 and later years	5.00%	4.00%	4.00%

The long-term rate of return on Plan assets is established based on MCV's expectations of asset returns for the investment mix in its Plan (with some reliance on historical asset returns for the Plans). The expected returns for various asset categories are blended to derive one long-term assumption.

Plan Assets. Citizens Bank has been appointed as trustee ("Trustee") of the Plan. The Trustee serves as investment consultant, with the responsibility of providing financial information and general guidance to the MCV Benefits Committee. The Trustee shall invest the assets of the Plan in the separate investment options in accordance with instructions communicated to the Trustee from time to time by the MCV Benefit Committee. The MCV Benefits Committee has the fiduciary and investment selection responsibility for the Plan. The MCV Benefits Committee consists of MCV Officers (excluding the President and Chief Executive Officer).

The MCV has a target allocation of 80% equities and 20% debt instruments. These investments emphasis total growth return, with a moderate risk level. The MCV Benefits Committee reviews the performance of the Plan investments quarterly, based on a long-term investment horizon and applicable benchmarks, with rebalancing of the investment portfolio, at the discretion of the MCV Benefits Committee.

MCV's Plan's weighted-average asset allocations, by asset category are as follows as of December 31:

	<u>2004</u>	<u>2003</u>
Asset Category:		
Cash and cash equivalents	1%	11%
Fixed income	19%	17%
Equity securities	<u>80%</u>	<u>72%</u>
Total	<u>100%</u>	<u>100%</u>

Contributions. MCV expects to contribute approximately \$.4 million to the Plan in 2005.

Retirement and Savings Plans

MCV sponsors a defined contribution retirement plan covering all employees. Under the terms of the plan, MCV makes contributions to the plan of either five or ten percent of an employee's eligible annual compensation dependent upon the employee's age. MCV also sponsors a 401(k) savings plan for employees. Contributions and costs for this plan are based on matching an employee's savings up to a maximum level. In 2004, 2003 and 2002, MCV contributed \$1.4 million, \$1.3 million and \$1.2 million, respectively under these plans.

Supplemental Retirement Benefits

MCV provides supplemental retirement, postretirement health care and excess benefit plans for key management. These plans are not qualified plans under the Internal Revenue Code; therefore, earnings of the trusts maintained by MCV to fund these plans are taxable to the Partners and trust assets are included in the assets of MCV.

(11) Partners' Equity and Related Party Transactions

The following table summarizes the nature and amount of each of MCV's Partner's equity interest, interest in profits and losses of MCV at December 31, 2004, and the nature and amount of related party

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)

transactions or agreements that existed with the Partners or affiliates as of December 31, 2004, 2003 and 2002, and for each of the twelve month periods ended December 31 (in thousands).

<u>Beneficial Owner, Equity Partner, Type of Partner and Nature of Related Party</u>	<u>Equity Interest</u>	<u>Interest</u>	<u>Related Party Transactions and Agreements</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>
CMS Energy Company						
CMS Midland, Inc.	\$396,888	49.0%	Power purchase agreements	\$601,535	\$513,774	\$557,149
General Partner; wholly-owned subsidiary of Consumers Energy Company			Purchases under gas transportation agreements	9,349	14,294	23,552
			Purchases under spot gas agreements	—	663	3,631
			Purchases under gas supply agreements	—	2,330	11,306
			Gas storage agreement	2,563	2,563	2,563
			Land lease/easement agreements	600	600	600
			Accounts receivable	50,364	40,373	44,289
			Accounts payable	1,031	1,025	3,502
			Sales under spot gas agreements	—	3,260	1,084
El Paso Corporation	\$141,397	18.1%				
Source Midland Limited Partnership ("SMLP")			Purchase under gas transportation agreements	12,334	13,023	12,463
General Partner; owned by subsidiaries of El Paso Corporation			Purchases under spot gas agreement	—	610	15,655
			Purchases under gas supply agreement	70,000	54,308	47,136
			Gas agency agreement	264	238	365
			Deferred reservation charges under gas purchase agreement	3,152	4,728	—
			Accounts receivable	—	—	523
			Accounts payable	10,997	5,751	7,706
			Sales under spot gas agreements	—	3,474	14,007
El Paso Midland, Inc. ("El Paso Midland") . . .	84,838	10.9	See related party activity listed under SMLP.			
General Partner; wholly-owned subsidiary of El Paso Corporation						
MEI Limited Partnership ("MEI")			See related party activity listed under SMLP.			
A General and Limited Partner; 50% interest owned by El Paso Midland, Inc. and 50% interest owned by SMLP						
General Partnership Interest	70,701	9.1				
Limited Partnership Interest	7,068	.9				
Micogen Limited Partnership ("MLP")	35,348	4.5	See related party activity listed under SMLP.			
Limited Partner, owned subsidiaries of El Paso Corporation						
Total El Paso Corporation	<u>\$339,352</u>	<u>43.5%</u>				
The Dow Chemical Company						
The Dow Chemical Company	\$ 73,735	7.5%	Steam and electric power agreement	39,055	36,207	29,385
Limited Partner			Steam purchase agreement — Dow Corning Corp (affiliate)	4,289	4,017	3,746
			Purchases under demineralized water supply agreement	8,142	6,396	6,605
			Accounts receivable	4,003	3,431	3,635
			Accounts payable	744	610	1,016
			Standby and backup fees	766	731	734
			Sales of gas under tolling agreement	—	—	6,442
Alanna Corporation						
Alanna Corporation	<u>\$ 1⁽¹⁾</u>	<u>.00001%</u>	Note receivable	1	1	1
Limited Partner; wholly-owned subsidiary of Alanna Holdings Corporation						

Footnotes to Partners' Equity and Related Party Transactions

(1) Alanna's capital stock is pledged to secure MCV's obligation under the lease and other overall lease transaction documents.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of Javelina Company:

In our opinion, the accompanying balance sheets and the related statements of operations, partners' capital and cash flows present fairly, in all material respects, the financial position of Javelina Company (the Partnership) at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

April 15, 2005
Houston, Texas

JAVELINA COMPANY
BALANCE SHEETS

	December 31,	
	2004	2003
	<i>(In Thousands of Dollars)</i>	
ASSETS		
Current assets		
Cash and cash equivalents	\$ 20,435	\$ 8,038
Accounts receivable, net		
Trade	30,778	10,613
Affiliates	3,281	6,770
Product inventory	941	—
Materials and supplies inventory	1,959	1,885
Prepaid expense	15	15
Total current assets	<u>57,409</u>	<u>27,321</u>
Property, plant and equipment, at cost		
Land	4,203	4,203
Liquids extraction plant	199,425	198,316
Accumulated depreciation	(125,347)	(116,655)
Total property, plant and equipment, net	<u>78,281</u>	<u>85,864</u>
Total assets	<u>\$ 135,690</u>	<u>\$ 113,185</u>
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable		
Trade	\$ 12,681	\$ 7,663
Affiliates	12,563	9,470
Ad valorem taxes payable	1,445	1,491
Accrued expenses	1,257	1,182
Total current liabilities	<u>27,946</u>	<u>19,806</u>
Commitments and contingencies		
Partners' capital	<u>107,744</u>	<u>93,379</u>
Total liabilities and partners' capital	<u>\$ 135,690</u>	<u>\$ 113,185</u>

The accompanying notes are an integral part of these financial statements.

JAVELINA COMPANY
STATEMENTS OF OPERATIONS

	Years Ended December 31,		
	2004	2003	2002
	<i>(In Thousands of Dollars)</i>		
Operating revenue			
Product revenue	\$284,049	\$181,318	\$135,720
Other revenue			
Interest income and other	<u>142</u>	<u>105</u>	<u>331</u>
	284,191	181,423	136,051
Operating Expenses			
Cost of product	171,913	137,726	86,675
Plant operating expenses	66,792	47,239	38,039
General and administrative	484	327	429
Depreciation	8,692	8,268	8,360
Ad valorem taxes	1,445	1,491	1,511
Bad debt expense	<u>—</u>	<u>—</u>	<u>197</u>
	<u>249,326</u>	<u>195,051</u>	<u>135,211</u>
Net income (loss)	<u><u>\$ 34,865</u></u>	<u><u>\$(13,628)</u></u>	<u><u>\$ 840</u></u>

The accompanying notes are an integral part of these financial statements.

JAVELINA COMPANY
STATEMENTS OF PARTNERS' CAPITAL
Years Ended December 31, 2004, 2003 and 2002

	El Paso Javelina, L.P. (40%)	El Paso Field Operations Company (40%)	K-M Javelina, L.P. (40%)	Valero Javelina, L.P. (20%)	Total	Accumulated Other Comprehensive Income
	<i>(In Thousands of Dollars)</i>					
Balances at January 1, 2002	\$ 44,747	\$ —	\$44,747	\$22,375	\$111,869	\$ 702
Net income	336	—	336	168	840	—
Distributions	(2,000)	—	(2,000)	(1,000)	(5,000)	—
Other comprehensive income — realized gain on cash flow hedges	(281)	—	(281)	(140)	(702)	(702)
Balances at December 31, 2002	42,802	—	42,802	21,403	107,007	—
Net loss	(9,876)	4,425	(5,451)	(2,726)	(13,628)	—
Sale of interests from El Paso Javelina, L.P. to El Paso Field Operations Company	(32,926)	32,926	—	—	—	—
Balances at December 31, 2003	—	37,351	37,351	18,677	93,379	—
Net income	—	13,946	13,946	6,973	34,865	—
Distributions	—	(8,200)	(8,200)	(4,100)	(20,500)	—
Balances at December 31, 2004	<u>\$ —</u>	<u>\$43,097</u>	<u>\$43,097</u>	<u>\$21,550</u>	<u>\$107,744</u>	<u>\$ —</u>

The accompanying notes are an integral part of these financial statements.

JAVELINA COMPANY
STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2004	2003	2002
	<i>(In Thousands of Dollars)</i>		
Cash flows from operating activities			
Net income (loss)	\$ 34,865	\$(13,628)	\$ 840
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Depreciation	8,692	8,268	8,360
Gain from sales of property, plant and equipment	—	—	(2)
Market value adjustment for derivative instruments	—	—	(539)
Changes in operating assets and liabilities			
Accounts receivable	(16,676)	(2,105)	(3,148)
Product inventory	(941)	—	3,112
Materials and supplies inventory	(74)	10	38
Accounts payable	8,111	3,802	(2,466)
Ad valorem taxes payable	(46)	(20)	1,511
Accrued expenses	75	(678)	184
Net cash provided by (used in) operating activities	<u>34,006</u>	<u>(4,351)</u>	<u>7,890</u>
Cash flows from investing activities			
Purchases of property, plant and equipment	(1,109)	(1,911)	(616)
Proceeds from sale of property, plant and equipment	—	—	2
Net cash used in investing activities	<u>(1,109)</u>	<u>(1,911)</u>	<u>(614)</u>
Cash flows from financing activities			
Distributions to partners	(20,500)	—	(5,000)
Net cash used in financing activities	<u>(20,500)</u>	<u>—</u>	<u>(5,000)</u>
Change in cash and cash equivalents	12,397	(6,262)	2,276
Cash and cash equivalents at beginning of year	<u>8,038</u>	<u>14,300</u>	<u>12,024</u>
Cash and cash equivalents at end of year	<u>\$ 20,435</u>	<u>\$ 8,038</u>	<u>\$14,300</u>

The accompanying notes are an integral part of these financial statements.

JAVELINA COMPANY
NOTES TO FINANCIAL STATEMENTS

1. Organization and Nature of Business

Javelina Company (the Partnership) was organized on November 4, 1988 as a Texas general partnership under a Partnership Agreement with a minimum term of 25 years for the purposes of acquiring, planning, designing, engineering, constructing, owning and operating a refinery off-gas processing plant located in the Corpus Christi, Texas area. The Partnership is owned 40 percent by El Paso Field Operations Company (El Paso Field, a wholly owned indirect subsidiary of El Paso Corporation); 40 percent by K-M Javelina, L.P. (Kerr-McGee, a wholly owned subsidiary of Kerr-McGee Corporation); and 20 percent by Valero Javelina, L.P. (Valero, a wholly owned subsidiary of Valero Energy Corporation). El Paso Javelina, L.P. (a wholly owned indirect subsidiary of El Paso Corporation) sold its 40 percent interest in the Partnership to El Paso Field in August 2003.

2. Significant Accounting Policies

Basis of Presentation

The Partnership's financial statements are prepared on the accrual basis of accounting in conformity with accounting principles generally accepted in the United States of America.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosures in these financial statements. Actual results can, and often do, differ from the estimates and assumptions used.

Cash and Cash Equivalents

Short-term investments with little risk of changes in value because of changes in interest rates and purchased with original maturity of less than three months are considered to be cash equivalents.

Accounts Receivable

Allowances for doubtful accounts are established using the specific identification method. Accounts receivable — trade are reported in the balance sheets net of allowance for doubtful accounts of \$292,500 as of December 31, 2004 and 2003. Accounts receivable — trade includes \$24,486,000 and \$10,064,000 of unbilled receivables as of December 31, 2004 and 2003, all of which were billed after year end. Accounts receivable — affiliates includes \$3,281,000 and \$6,770,000 of unbilled receivables as of December 31, 2004 and 2003, all of which were billed after year end.

Gas Imbalances

Gas imbalances result from over or under delivery of gas under various processing and sales agreements. Gas imbalances are settled in the following month with delivery or receipt of makeup gas or by cash in accordance with contractual terms. Gas imbalances are valued at the Partnership's current month average purchase cost of gas and may be impacted by changes in natural gas prices. As of December 31, 2003, accounts receivable — trade included \$494,000 of gas imbalances receivable. As of December 31, 2004, accounts payable — trade included \$33,000 of gas imbalances payable. As of December 31, 2004 and 2003, accounts payable — affiliates included \$1,395,000 and \$452,000, respectively, of gas imbalances payable.

Inventories

The Partnership accounts for product inventory on a first-in, first-out basis and materials and supplies inventories at average cost. Both inventories are valued at the lower of average cost or market.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost and includes management fees paid on capital acquisition costs under the operating agreement (see Note 3). Expenditures that increase the capacity or operating efficiency or extend the useful life of an asset are capitalized. Depreciation is provided on a straight-line basis over lives ranging from 10 to 23 years. Assets retired, sold, or disposed are recorded by eliminating the related cost and accumulated depreciation with any resulting gain or loss reflected in income.

Impairment and Disposal of Long-lived Assets

The Partnership evaluates long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If the projected undiscounted future cash flows from the use and eventual disposition of the asset is less than the asset's carrying amount, the asset is written down to its fair value and an impairment loss is recorded in the statement of operations.

Fair Value of Financial Instruments

The estimated fair values of cash and cash equivalents, accounts receivable, accounts payable and accrued expenses approximate their carrying amounts due to the short-term maturity of these instruments.

Revenue Recognition

The Partnership recognizes revenue for the sale of products, excluding hydrogen, in the period of delivery. Under terms of a hydrogen sales contract, as consideration for hydrogen supplied to the customer, the customer is required to deliver natural gas containing 130% of the British Thermal Units contained in the hydrogen supplied to the customer. Such exchanges of product have been treated as non-monetary exchanges in accordance with Accounting Principles Board (APB) Opinion No. 29, *Accounting for Nonmonetary Transactions*, and accordingly, no sales or purchases of product are reflected in the statements of operations. The value of these exchanges were \$27.2 million, \$19.2 million and \$12.1 million for the years ended December 31, 2004, 2003 and 2002, respectively.

Repair and Maintenance Costs

The cost of most planned major repair and maintenance activity is accrued and charged to expense in a systematic and rational manner over the estimated period extending to the next planned major maintenance activity. Other repair and maintenance costs are charged to expense as incurred.

Federal Income Taxes

Javelina Company is organized as a partnership and is therefore, not subject to taxation for federal or state income tax purposes. The taxable income or loss resulting from the Partnership's operations will ultimately be included in the federal and state tax returns of the individual partners. Accordingly, no provision for income taxes has been recorded in the accompanying financial statements.

Income Allocation and Distributions

Under the terms of the Partnership Agreement, all income, gains, losses, deductions, credits and distributions of excess cash are allocated to the partners based on their ownership interest in the Partnership. Distributions are determined by the Management Committee. In 2004 and 2002, the Partnership declared and paid cash distributions of \$20.5 million and \$5 million, respectively. No distribution was declared for the year ended December 31, 2003. In January and February 2005, the Partnership declared and paid cash distributions totalling \$11.3 million.

Derivative Instruments and Hedging Activities

In November 2000, as part of its risk management strategy to offset the variability of expected future cash flows as a result of changes in ethylene and natural gas commodity prices, the Partnership entered into derivative contracts expiring in December 2003 to sell ethylene and purchase natural gas. Effective January 2001, the Partnership accounted for these contracts under Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, that requires all derivative instruments be recorded on the balance sheet at their fair values. Gains and losses related to changes in fair values of derivatives that qualify, are designated, and are effective as cash flow hedges are deferred and recorded as components of other comprehensive income. Amounts in accumulated other comprehensive income are reclassified into earnings in the same period the hedged transaction affects earnings. Hedge accounting is discontinued prospectively when a derivative is terminated or no longer effective and related gains and losses are recognized immediately in current-period earnings. Amounts included in accumulated other comprehensive income at the time the derivative is terminated or no longer effective remain and are reclassified into earnings in the same period the hedged transaction affects earnings. In September 2001, the ethylene contract became ineffective as a result of credit risk with the counterparty. Under guidance provided by the Financial Accounting Standards Board's Derivatives Implementation Group in Issue G-10, hedge accounting was discontinued prospectively. In addition, no fair value was assigned to the contract and a loss equal to the value of the asset immediately prior to its ineffectiveness was recognized in earnings. In 2002, both contracts were terminated. Of the \$702,000 included in accumulated other comprehensive income as of December 31, 2001, \$163,000, related to changes in fair value, was recognized as a reduction of accumulated other comprehensive income through the date the natural gas contract was terminated, and \$539,000 was recognized in earnings in connection with the settlement of the contracts. The Partnership also recognized an additional \$275,000 in earnings in connection with the settlement of the contracts. Of these amounts recognized in earnings, \$736,000 was included in product revenue and \$78,000 was included as an offset to cost of product. There were no material gains or losses associated with hedged transactions in 2003.

3. Transactions With Affiliates

Transactions with partners are governed under the terms and conditions of the Partnership Agreement.

The Partnership has an operating agreement with El Paso Field. The agreement was transferred from El Paso Javelina, L.P. upon the sale of its 40 percent interest in the Partnership to El Paso Field. Under the agreement, El Paso Field, acting as project manager, generally pays costs and expenses incurred by the Partnership. El Paso Field is reimbursed 100 percent for all such costs and expenses and, in addition, receives a management fee equal to 15 percent of qualifying operating expenses and up to 10 percent of plant and equipment expenditures.

Under the terms of processing agreements with Valero Refining Company and Valero Refining and Marketing Company, wholly owned subsidiaries of Valero Energy Corporation, the Partnership pays processing fees equal to 25% of monthly profits derived from products extracted from refinery off gas received, if any, as defined. In addition, gas imbalance settlements are settled in the following month with delivery or receipt of makeup gas or by cash in accordance with contractual terms. Under the terms of a transportation agreement with Javelina Pipeline Company, a partnership owned by El Paso Field, Kerr McGee and Valero, Javelina Pipeline Company receives, transports and redelivers all or part of the Partnership's gas for a contractual price.

During 1989, the Partnership entered into a 25-year surface rental agreement with El Paso Merchant Energy-Petroleum Company, a wholly owned indirect subsidiary of El Paso Corporation. The remaining aggregate minimum lease payments under the long-term operating lease are \$77,880 per year for 2005 to 2008 and \$81,000 per year thereafter until the agreement ends in December 2013.

The following table summarizes transactions with affiliates related to these agreements and other sales of product or purchases of gas from affiliates as of and for the years ended December 31, 2004, 2003 and 2002.

	(In Thousands of Dollars)		
	2004	2003	2002
<i>Product revenue:</i>			
<i>El Paso Corporation</i>			
Sales to El Paso NGL Marketing Company, L.P., a wholly owned indirect subsidiary of El Paso Corporation	\$42,494	\$41,726	\$29,046
Sales to El Paso Merchant Energy — Petroleum Company . . .	—	237	6,891
<i>Valero Energy Corporation</i>			
Sales to Valero Refining Company	<u>35,002</u>	<u>25,304</u>	<u>20,492</u>
	<u>\$77,496</u>	<u>\$67,267</u>	<u>\$56,429</u>
<i>Cost of product:</i>			
<i>El Paso Corporation</i>			
Gas purchases from El Paso Industrial Energy, a wholly owned indirect subsidiary of El Paso Corporation	\$65,912	\$37,154	\$ 6,542
<i>Valero Energy Corporation</i>			
Gas imbalance settlements paid to Valero Refining Company	2,819	4,883	2,416
Gas imbalance settlements paid to (received from) Valero Refining and Marketing Company	<u>8,336</u>	<u>(2,161)</u>	<u>(43)</u>
	<u>\$77,067</u>	<u>\$39,876</u>	<u>\$ 8,915</u>
<i>Plant operating expenses:</i>			
<i>El Paso Corporation</i>			
Management fees paid to El Paso Field on qualifying expenses	\$ 1,347	\$ 1,333	\$ 1,302
Transportation fees paid to Javelina Pipeline Company	1,852	1,672	1,656
Surface rentals paid to El Paso Merchant Energy-Petroleum Company	78	75	84
<i>Valero Energy Corporation</i>			
Processing fees paid to Valero Refining Company	1,588	586	316
Processing fees paid to Valero Refining and Marketing Company	<u>3,900</u>	<u>185</u>	<u>164</u>
	<u>\$ 8,765</u>	<u>\$ 3,851</u>	<u>\$ 3,522</u>
<i>Accounts receivable — affiliates:</i>			
<i>El Paso Corporation</i>			
Accounts receivable due from El Paso NGL Marketing Company, L.P.	\$ —	\$ 4,308	
<i>Valero Energy Corporation</i>			
Accounts receivable due from Valero Refining Company	<u>3,281</u>	<u>2,462</u>	
	<u>\$ 3,281</u>	<u>\$ 6,770</u>	
<i>Property, plant and equipment:</i>			
Capitalized management fees paid to El Paso Field on plant and equipment expenditures	<u>\$ 59</u>	<u>\$ 74</u>	

	<u>(In Thousands of Dollars)</u>		
	<u>2004</u>	<u>2003</u>	<u>2002</u>
<i>Accounts payable — affiliates:</i>			
<i>El Paso Corporation</i>			
Accounts payable due to El Paso Industrial Energy for gas purchases	\$ 5,394	\$ 4,608	
Accounts payable due to El Paso Field for reimbursable items and management fees	4,574	4,155	
Accounts payable due to Javelina Pipeline Company for transportation fees	310	255	
<i>Valero Energy Corporation</i>			
Accounts payable due to Valero Refining Company for gas imbalance settlements	331	361	
Accounts payable due to Valero Refining and Marketing Company for gas imbalance settlements	1,064	91	
Accounts payable due to Valero Refining and Marketing Company for processing fees	890	—	
	<u>\$12,563</u>	<u>\$ 9,470</u>	

4. Sales and Processing Agreements

The Partnership has entered into various sales agreements with terms up to three years whereby the customer has agreed to purchase certain base quantities of the Partnership's products at contractual prices based on market price indexes. In addition, one contract requires the Partnership to pay an access fee of \$90,000 per year and transportation fees to pipeline companies for delivery of product to the customer. These costs are included in plant operating expenses in the statements of operations.

The Partnership entered into processing fee agreements with certain refinery off gas suppliers. Under these agreements, the Partnership pays a processing fee equal to 25% of monthly profits derived from products extracted from off gas received, if any, as defined. In May 2003, under terms of the agreements, the Partnership notified the suppliers that it would terminate the processing agreements in six months. Since their termination, the agreements have been extended on a month to month basis pending renegotiation.

5. Commitments and Contingencies

In the normal course of business, the Partnership may become party to certain lawsuits and administrative proceedings before various courts and governmental agencies involving, for example, contractual matters and environmental issues. While the outcome of these items cannot be predicted with certainty, based on information known to date, management does not expect the ultimate resolution of any matters will have a material adverse effect on the Partnership's financial statements.

Management is not aware of any contingency that could have a material adverse effect on the Partnership's financial position, results of operations or cash flows as of December 31, 2004.

Report of Independent Registered Public Accounting Firm

The Partners

Great Lakes Gas Transmission Limited Partnership:

We have audited the accompanying consolidated balance sheets of Great Lakes Gas Transmission Limited Partnership and subsidiary (Partnership) as of December 31, 2004 and 2003, and the related consolidated statements of income and partners' capital, and cash flows for each of the years in the three year period ended December 31, 2004. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Great Lakes Gas Transmission Limited Partnership and subsidiary as of December 31, 2004 and 2003, and the results of their operations and their cash flows each of the years in the three year period ended December 31, 2004 in conformity with U. S. generally accepted accounting principles.

Detroit, Michigan
January 11, 2005

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP

**CONSOLIDATED STATEMENTS OF
INCOME AND PARTNERS' CAPITAL**

	Years Ended December 31		
	2004	2003	2002
	<i>(Thousands of Dollars)</i>		
Transportation Revenues	\$ 284,327	\$ 279,208	\$ 277,515
Operating Expenses			
Operation and Maintenance	34,723	43,052	37,075
Depreciation	57,756	57,238	56,916
Income Taxes Payable by Partners	47,058	40,530	45,400
Property and Other Taxes	23,265	24,929	14,393
	162,802	165,749	153,784
Operating Income	121,525	113,459	123,731
Other Income (Expense)			
Interest on Long Term Debt	(37,718)	(40,239)	(44,539)
Other, Net	1,373	1,102	3,850
	(36,345)	(39,137)	(40,689)
Net Income	\$ 85,180	\$ 74,322	\$ 83,042
Partners' Capital			
Balance at Beginning of Year	\$ 452,007	445,512	443,640
Contributions by General Partners	29,398	22,459	25,432
Net Income	85,180	74,322	83,042
Current Income Taxes Payable by Partners Charged to Earnings	31,536	24,238	27,801
Distributions to Partners	(177,620)	(114,524)	(134,403)
Balance at End of Year	\$ 420,501	\$ 452,007	\$ 445,512

The accompanying notes are an integral part of these statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED BALANCE SHEETS

	As of December 31	
	2004	2003
	<i>(Thousands of Dollars)</i>	
ASSETS		
Current Assets		
Cash and Cash Equivalents	\$ 59,034	\$ 40,156
Accounts Receivable	44,137	34,747
Materials and Supplies, at Average Cost	10,043	10,020
Prepayments and Other	5,146	3,511
	118,360	88,434
Gas Utility Plant		
Property, Plant and Equipment	2,015,202	2,011,279
Less Accumulated Depreciation	919,287	870,356
	1,095,915	1,140,923
	\$1,214,275	\$1,229,357
LIABILITIES & PARTNERS' CAPITAL		
Current Liabilities		
Current Maturities of Long Term Debt	\$ 10,000	\$ 10,000
Accounts Payable	27,984	14,850
Property and Other Taxes	24,107	25,077
Accrued Interest and Other	13,580	14,025
	75,671	63,952
Long Term Debt	460,000	470,000
Other Liabilities		
Amounts Equivalent to Deferred Income Taxes	256,959	241,281
Other	1,144	2,117
	258,103	243,398
Partners' Capital	420,501	452,007
	\$1,214,275	\$1,229,357

The accompanying notes are an integral part of these statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31		
	2004	2003	2002
	<i>(Thousands of Dollars)</i>		
Cash Flow Increase (Decrease) from:			
Operating Activities			
Net Income	\$ 85,180	\$ 74,322	\$ 83,042
Adjustments to Reconcile Net Income to Operating Cash Flows:			
Depreciation	57,756	57,238	56,916
Amounts Equivalent to Deferred Income Taxes	15,678	16,983	18,241
Allowance for Funds Used During Construction	(157)	(398)	(500)
Changes in Current Assets and Liabilities:			
Accounts Receivable	(9,390)	1,529	(6,250)
Accounts Payable	13,134	(1,642)	2,148
Property and Other Taxes	(970)	(1,687)	(1,131)
Other	(3,076)	(337)	678
	158,155	146,008	153,144
Investment in Utility Plant	(12,591)	(27,277)	(34,292)
Financing Activities			
Repayment of Long Term Debt	(10,000)	(41,500)	(47,250)
Contributions by General Partners	29,398	22,459	25,432
Current Income Taxes Payable by Partners Charged to Earnings	31,536	24,238	27,801
Distribution to Partners	(177,620)	(114,524)	(134,403)
	(126,686)	(109,327)	(128,420)
Change in Cash and Cash Equivalents	18,878	9,404	(9,568)
Cash and Cash Equivalents:			
Beginning of Year	40,156	30,752	40,320
End of Year	\$ 59,034	\$ 40,156	\$ 30,752
Supplemental Disclosure of Cash Flow Information			
Cash Paid During the Year for Interest			
(Net of Amounts Capitalized of \$48, \$150 and \$214, Respectively)	\$ 37,903	\$ 40,576	\$ 45,004

The accompanying notes are an integral part of these statements.

GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1 Organization and Management

Great Lakes Gas Transmission Limited Partnership (Partnership) is a Delaware limited partnership that owns and operates an interstate natural gas pipeline system. The Partnership transports natural gas for delivery to customers in the midwestern and northeastern United States and eastern Canada. Partnership ownership percentages are recalculated each year to reflect distributions and contributions.

The partners, their parent companies, and partnership ownership percentages are as follows:

<u>Partner (Parent Company)</u>	<u>Ownership %</u>	
	<u>2004</u>	<u>2003</u>
General Partners:		
El Paso Great Lakes, Inc. (El Paso Corporation)	46.61	46.33
TransCanada GL, Inc. (TransCanada PipeLines Ltd.)	46.61	46.33
Limited Partner:		
Great Lakes Gas Transmission Company (TransCanada PipeLines Ltd. and El Paso Corporation)	6.78	7.34

The day-to-day operation of Partnership activities is the responsibility of Great Lakes Gas Transmission Company (Company), which is reimbursed for its employee salaries, benefits and other expenses, pursuant to the Partnership's Operating Agreement with the Company.

2 Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of the Partnership and GLGT Aviation Company, a wholly owned subsidiary. GLGT Aviation Company owns a transport aircraft used principally for pipeline operations. Intercompany amounts have been eliminated.

For purposes of reporting cash flows, the Partnership considers all liquid investments with original maturities of three months or less to be cash equivalents.

The Partnership recognizes revenues from natural gas transportation in the period the service is provided.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the use of estimates and assumptions that affect the amounts reported as assets, liabilities, revenues and expenses and the disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Regulation

The Partnership is subject to the rules, regulations and accounting procedures of the Federal Energy Regulatory Commission (FERC). The Partnership's accounting policies follow regulatory accounting principles prescribed under Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*. Regulatory assets and liabilities have been established and represent probable future revenue or expense which will be recovered from or refunded to customers.

Accounts Receivable

Accounts receivable are reported net of an allowance for doubtful accounts of \$1,200,000 and \$2,304,000 for 2004 and 2003, respectively. Accounts receivable are recorded at the invoiced amount. Late fees are recognized as income when earned. The Partnership establishes an allowance for losses on accounts receivable if it is determined that all or a portion of the outstanding balance will not be collected. The Partnership also

considers historical industry data and customer credit trends. Account balances are charged off against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote.

Gas Utility Plant and Depreciation

Gas utility plant is stated at cost and includes certain administrative and general expenses, plus an allowance for funds used during construction. The cost of plant retired is charged to accumulated depreciation. Depreciation of gas utility plant is computed using the straight-line method. The Partnership's principal operating assets are depreciated at an annual rate of 2.75%.

The allowance for funds used during construction represents the debt and equity costs of capital funds applicable to utility plant under construction, calculated in accordance with a uniform formula prescribed by the FERC. The rates used were 10.49%, 10.41% and 10.36% for years 2004, 2003, and 2002, respectively.

Asset Retirement Obligations

Effective January 1, 2003, the Partnership adopted SFAS No. 143 "Accounting for Asset Retirement Obligations" (Statement 143). Statement 143 requires recognition of the fair value of legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction, development, and/or normal operation of a long-lived asset. The Partnership has asset retirement obligations if it were to permanently retire all or part of the pipeline system; however, the fair value of the obligations cannot be determined because the end of the system life is indeterminable.

Income Taxes

The Partnership's tariff includes an allowance for income taxes, which the FERC requires the Partnership to record as if it were a corporation. The provisions for current and deferred income tax expense are recorded without regard to whether each partner can utilize its share of the Partnership's tax deductions. Income taxes are deducted in the Consolidated Statements of Income and the current portion of income taxes is returned to partners' capital. Recorded current income taxes are distributed to partners based on their ownership percentages.

Amounts equivalent to deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases at currently enacted income tax rates.

3 Affiliated Company Transactions

Affiliated company amounts included in the Partnership's consolidated financial statements, not otherwise disclosed, are as follows:

	(In Thousands)		
	2004	2003	2002
Accounts receivable	\$ 12,827	16,062	15,989
Accounts payable	1,845	1,135	622
Transportation revenues:			
TransCanada PipeLines Ltd. and affiliates	164,810	166,578	163,442
El Paso Corporation and affiliates	20,581	23,877	24,875

Affiliated transportation revenues are primarily provided under fixed priced contracts with remaining terms ranging from 1 to 8 years.

The Partnership reimburses the Company for salaries, benefits and other incurred expenses. Benefits include pension, savings plan, and other post-retirement benefits. Operating expenses charged by the Company in 2004, 2003 and 2002 were \$17,388,000, \$25,758,000 and \$17,888,000, respectively.

The Company makes contributions for eligible employees of the Company to a voluntary defined contribution plan sponsored by one of the parent companies. The Company's contributions, which are based on matching employee contributions, amounted to \$475,000, \$396,000, and \$770,000 in 2004, 2003 and 2002, respectively.

The Company participates in the El Paso Corporation cash balance pension plan and post-retirement plan. The Company accounts for pension and post-retirement benefits on an accrual basis. The net expense (income) for each of the plans are as follows:

	(In Thousands)		
	<u>2004</u>	<u>2003</u>	<u>2002</u>
Pension	\$(743,000)	(2,600,000)	(5,400,000)
Post-Retirement	202,000	204,000	236,000

4 Debt

	(In Thousands)	
	<u>2004</u>	<u>2003</u>
Senior Notes, unsecured, interest due semiannually, principal due as follows:		
8.74% series, due 2003 to 2011	\$ 70,000	80,000
9.09% series, due 2012 to 2021	100,000	100,000
6.73% series, due 2009 to 2018	90,000	90,000
6.95% series, due 2019 to 2028	110,000	110,000
8.08% series, due 2021 to 2030	100,000	100,000
	470,000	480,000
Less current maturities	10,000	10,000
Total long term debt less current maturities	<u>\$460,000</u>	<u>470,000</u>

The aggregate estimated fair value of long term debt was \$559,800,000 and \$571,400,000 for 2004 and 2003, respectively. The fair value is determined using discounted cash flows based on the Partnership's estimated current interest rates for similar debt.

The aggregate annual required repayments of Senior Notes is \$10,000,000 for each year 2005 through 2008 and \$19,000,000 in 2009.

Under the most restrictive covenants in the Senior Note Agreements, approximately \$253,000,000 of partners' capital is restricted as to distributions as of December 31, 2004.

5 Income Taxes Payable by Partners

Income taxes payable by partners for the years ended December 31, 2004, 2003 and 2002 consists of:

	(In Thousands)		
	2004	2003	2002
Current			
Federal	\$30,187	23,201	26,612
State	<u>1,349</u>	<u>1,037</u>	<u>1,189</u>
	<u>31,536</u>	<u>24,238</u>	<u>27,801</u>
Deferred			
Federal	14,833	15,556	16,808
State	<u>689</u>	<u>736</u>	<u>791</u>
	<u>15,522</u>	<u>16,292</u>	<u>17,599</u>
	<u>\$47,058</u>	<u>40,530</u>	<u>45,400</u>

Income taxes payable by partners differs from the statutory rate of 35% due to the amortization of excess deferred taxes along with the effects of state and local taxes. The Partnership is required to amortize excess deferred taxes which had previously been accumulated at tax rates in excess of current statutory rates. Such amortization reduced income taxes payable by partners by \$575,000 for 2004 and \$900,000 for 2003 and 2002. The excess deferred taxes were fully amortized at December 31, 2004.

Amounts equivalent to deferred income taxes are principally comprised of temporary differences associated with excess tax depreciation on utility plant. As of December 31, 2004 and 2003, no valuation allowance is required. The deferred tax assets and deferred tax liabilities as of December 31, 2004 and 2003 are as follows:

	(In Thousands)	
	2004	2003
Deferred tax assets — other	\$ 4,889	5,168
Deferred tax liabilities — utility plant	(245,786)	(230,614)
Deferred tax liabilities — other	<u>(16,062)</u>	<u>(15,835)</u>
Net deferred tax liability	<u>\$ (256,959)</u>	<u>(241,281)</u>

6 Severance Costs

In 2003, the Partnership implemented a reorganization plan to reduce the work force, and recorded severance costs of approximately \$6 million. All amounts were substantially paid by December 31, 2003. Severance costs have been included in Operation and Maintenance expense.

7 Use Tax Refunds

In the first quarter of 2002, Great Lakes received a favorable decision from the Minnesota Supreme Court on use tax litigation and has collected refunds and related interest on litigated claims and pending claims for 1994 to 2001. The total amount received was \$13.7 million. The refunds are reflected in Property and Other Taxes (\$10.9 million) and the interest included in Other, Net (\$2.8 million).

EXHIBIT LIST
December 31, 2004

Exhibits not incorporated by reference to a prior filing are designated by an “*”; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

<u>Exhibit Number</u>	<u>Description</u>
3.A	Amended and Restated Certificate of Incorporation dated March 7, 2002 (Exhibit 3.A to our 2001 Form 10-K).
3.B	By-laws dated June 24, 2002 (Exhibit 3.B to our 2002 Form 10-K).
4.A	Indenture dated as of February 15, 1994 and First Supplemental Indenture dated as of February 15, 1994.
4.B	Indenture dated as of March 5, 2003 between ANR Pipeline Company and The Bank of New York Trust Company, N.A., successor to The Bank of New York, as Trustee (Exhibit 4.1 to our Form 8-K filed March 5, 2003).
10.A	Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 10.A to our Form 8-K filed November 29, 2004).
10.B	Amended and Restated Security Agreement dated as of November 23, 2004, made by among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 10.B to our Form 8-K filed November 29, 2004).
10.C	\$3,000,000,000 Revolving Credit Agreement dated as of April 16, 2003 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company and ANR Pipeline Company, as Borrowers, the Lenders Party thereto, and JPMorgan Chase Bank, as Administrative Agent, ABN Amro Bank N.V. and Citicorp North America, Inc., as Co-Document Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents, J.P. Morgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers. (Exhibit 99.1 to El Paso Corporation’s Form 8-K filed April 18, 2003); First Amendment to the \$3,000,000,000 Revolving Credit Agreement and Waiver dated as of March 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.1 to our 2003 First Quarter Form 10-Q); Second Waiver to the \$3,000,000,000 Revolving Credit Agreement dated as of June 15, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents (Exhibit 10.A.2 to our 2003 Second Quarter Form 10-Q); Second Amendment to the \$3,000,000,000 Revolving Credit Agreement and Third

<u>Exhibit Number</u>	<u>Description</u>
	Waiver dated as of August 6, 2004 among El Paso Corporation, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, ANR Pipeline Company and Colorado Interstate Gas Company, as Borrowers, the Lenders party thereto and JPMorgan Chase Bank, as Administrative Agent, ABN AMRO Bank N.V. and Citicorp North America, Inc., as Co-Documentation Agents, Bank of America, N.A. and Credit Suisse First Boston, as Co-Syndication Agents. (Exhibit 99.B to our Form 8-K filed August 10, 2004).
21	Omitted pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.
*31.A	Certification of Chief Executive Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*31.B	Certification of Chief Financial Officer pursuant to sec. 302 of the Sarbanes-Oxley Act of 2002.
*32.A	Certification of Chief Executive Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.
*32.B	Certification of Chief Financial Officer pursuant to 18 U.S.C. sec. 1350 as adopted pursuant to sec. 906 of the Sarbanes-Oxley Act of 2002.

Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso CGP Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 20th day of June 2005.

EL PASO CGP COMPANY
Registrant

/s/ DOUGLAS L. FOSHEE

Douglas L. Foshee
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of El Paso CGP Company and in the capacities and on the dates indicated:

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ DOUGLAS L. FOSHEE</u> (Douglas L. Foshee)	President, Chief Executive Officer, Chairman of the Board and Director (Principal Executive Officer)	June 20, 2005
<u>/s/ D. DWIGHT SCOTT</u> (D. Dwight Scott)	Executive Vice President, Chief Financial Officer and Director (Principal Financial Officer)	June 20, 2005
<u>/s/ ROBERT W. BAKER</u> (Robert W. Baker)	Executive Vice President, General Counsel and Director	June 20, 2005
<u>/s/ JEFFREY I. BEASON</u> (Jeffrey I. Beason)	Senior Vice President and Controller (Principal Accounting Officer)	June 20, 2005